an e·on company

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SEP 11 2008

PUBLIC SERVICE COMMISSION

**Louisville Gas and Electric Company**
State Regulation and Rates
220 West Main Street
PO Box 32010
Louisville, Kentucky 40232
www.eon-us.com

Lonnie E. Bellar
Vice President
T 502-627-4830
F 502-217-2109
lonnie.bellar@eon-us.com

Ms. Stephanie L. Stumbo
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, Kentucky 40601

September 11, 2008

**RE:** ***Application of Louisville Gas and Electric Company for an Adjustment of Its Electric and Gas Base Rates* – Case No. 2008-00252**

***Application of Louisville Gas and Electric Company to File Depreciation Study* – Case No. 2007-00564**

Dear Ms. Stumbo:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Louisville Gas and Electric Company to the Commission Staff's Second Set of Data Requests dated August 27, 2008, in the above-referenced matters.

Also, enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding certain information requested in Question Nos. 10(a)-(b), 80(b), 89(b)(1)-(5), 91(b), (c), (d), (e)(1), (f)(1), 104, and 105.

Should you have any questions regarding the enclosed, please contact me at your convenience.

Sincerely,

Lonnie E. Bellar

Lonnie E. Bellar

cc: Parties of Record

1\2

Counsel of Record

Allyson K. Sturgeon, Senior Corporate Attorney – E.ON U.S. LLC
Kendrick R. Riggs – Stoll Keenon Ogden PLLC (Louisville Gas and Electric)
W. Duncan Crosby – Stoll Keenon Ogden PLLC (Louisville Gas and Electric)
Robert M. Watt – Stoll Keenon Ogden PLLC (Louisville Gas and Electric)
Dennis Howard II – Office of the Attorney General (AG)
Lawerence W. Cook – Office of the Attorney General (AG)
Paul D. Adams – Office of the Attorney General (AG)
Michael L. Kurtz – Boehm, Kurtz & Lowry (KIUC)
Lisa Kilkelly – Legal Aid Society, Inc. (ACM and POWER)
David C. Brown – Stites and Harbison (Kroger)
Joe F. Childers (CAK)

Consultants to the Parties

Steve Seelye – The Prime Group (E.ON U.S. LLC)
William A. Avera – FINCAP, Inc (E.ON U.S. LLC)
John Spanos – Gannett Fleming, Inc. (E.ON U.S. LLC)
Robert Henkes (AG)
Michael Majoros – Snavely King Majoros O'Connor & Lee (AG)
Glenn Watkins – Technical Associates (AG)
Dr. J. Randall Woolridge – Smeal College of Business (AG)
Lane Kollen – Kennedy and Associates (KIUC)
Kevin C. Higgins – Energy Strategies, LLC (Kroger)

**COMMONWEALTH OF KENTUCKY**

**BEFORE THE PUBLIC SERVICE COMMISSION**

**In the Matter of:**

| | | |
|---|---|---|
| **APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ADJUSTMENT OF ITS ELECTRIC AND GAS BASE RATES** | ) ) ) ) | **CASE NO. 2008-00252** |
| **APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY TO FILE DEPRECIATION STUDY** | ) ) ) | **CASE NO. 2007-00564** |

**RESPONSE OF**
**LOUISVILLE GAS AND ELECTRIC COMPANY**
**TO THE**
**SECOND DATA REQUEST OF COMMISSION STAFF**
**DATED AUGUST 27, 2008**

**FILED: September 11, 2008**

**VERIFICATION**

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **S. Bradford Rives**, being duly sworn, deposes and says that he is the Chief Financial Officer, for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

SBRives
**S. BRADFORD RIVES**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

## VERIFICATION

**COMMONWEALTH OF KENTUCKY** )
) **SS:**
**COUNTY OF JEFFERSON** )

The undersigned, **Chris Hermann**, being duly sworn, deposes and says he is Senior Vice President – Energy Delivery for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

C Hermann
**CHRIS HERMANN**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

## VERIFICATION

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Paula H. Pottinger, Ph.D.**, being duly sworn, deposes and says that she is the Senior Vice President, Human Resources for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Paula H. Pottinger
**PAULA H. POTTINGER, Ph.D.**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

## VERIFICATION

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Paul W. Thompson**, being duly sworn, deposes and says that he is the Senior Vice President, Energy Services for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

[signature]
**PAUL W. THOMPSON**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY** )
) **SS:**
**COUNTY OF JEFFERSON** )

The undersigned, **Lonnie E. Bellar**, being duly sworn, deposes and says that he is the Vice President, State Regulation and Rates for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Lonnie E Bellar
**LONNIE E. BELLAR**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Valerie L. Scott**, being duly sworn, deposes and says that she is the Controller, for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Valerie L. Scott
**VALERIE L. SCOTT**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

## VERIFICATION

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Shannon L. Charnas**, being duly sworn, deposes and says that she is the Director, Utility Accounting for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Shannon L Charnas
**SHANNON L. CHARNAS**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:
November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Butch Cockerill**, being duly sworn, deposes and says that he is Director, Revenue Collection for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Butch Cockerill
**BUTCH COCKERILL**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Robert M. Conroy**, being duly sworn, deposes and says that he is the Director, Rates for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

**ROBERT M. CONROY**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Ely (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY** )
) **SS:**
**COUNTY OF JEFFERSON** )

The undersigned, **J. Clay Murphy**, being duly sworn, deposes and says that he is the Director, Gas Management, Planning, and Supply for Louisville Gas and Electric Company, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

J Clay Murphy
**J. CLAY MURPHY**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

**VERIFICATION**

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **Caryl M. Pfeiffer**, being duly sworn, deposes and says that she is the Director Corporate Fuels and By-Products, for Louisville Gas and Electric Company, that she has personal knowledge of the matters set forth in the responses for which she is identified as the witness, and the answers contained therein are true and correct to the best of her information, knowledge and belief.

Caryl M. Pfeiffer
CARYL M. PFEIFFER

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

Tammy J. Elzy (SEAL)
Notary Public

My Commission Expires:

November 9, 2010

## VERIFICATION

**STATE OF KENTUCKY )**
**) SS:**
**COUNTY OF JEFFERSON )**

The undersigned, **William Steven Seelye**, being duly sworn, deposes and says that he is the Senior Consultant and Principal, for The Prime Group, LLC, that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

_______________________
**WILLIAM STEVEN SEELYE**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 9th day of September, 2008.

_______________________(SEAL)
Notary Public

My Commission Expires:

November 9, 2010

## VERIFICATION

**COMMONWEALTH OF PENNSYLVANIA** )
) **SS:**
**COUNTY OF CUMBERLAND** )

The undersigned, **John J. Spanos**, being duly sworn, deposes and says that he is the Vice President, Valuation and Rate Division for Gannett Fleming, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

John J. Spanos
**JOHN J. SPANOS**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of September, 2008.

(SEAL)
Notary Public

My Commission Expires:

February 20, 2011

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Cheryl Ann Rutter, Notary Public
East Pennsboro Twp., Cumberland County
My Commission Expires Feb. 20, 2011
Member, Pennsylvania Association of Notaries

# VERIFICATION

**STATE OF TEXAS** )
) **SS:**
**COUNTY OF TRAVIS** )

The undersigned, **William E. Avera**, being duly sworn, deposes and says that he is President of FINCAP, Inc., that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

**WILLIAM E. AVERA**

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 8th day of September, 2008.

____________________(SEAL)
Notary Public

My Commission Expires:
1/10/2011

ADRIEN MCKENZIE
Notary Public
STATE OF TEXAS
My Comm Exp Jan 10, 2011

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 1

Responding Witness: Robert M. Conroy

Q-1. Refer to Volume 1 of 5 of LG&E's application, at Tab 8.

a. For each of the tariffs that include a change in either the kW or kWh to qualify, explain why the change was made.

b. For the tariffs which eliminated the charge for the transmission line, explain why the change was made.

A-1. a. The current rate structures were set in place prior to modern metering technologies and when usage patterns were significantly different. Changes were made to the availability of rates to insure more homogeneous customer groupings and provide more consistent and truer price signals to the customers. Specific changes are listed below.

**GS, General Service,** is currently available to new secondary customers with loads up to 500 kW. GS is also currently available to 'grandfathered' secondary and primary customers not meeting the 500kW limitation.

Originally GS was offered as the differentiating rate to RS, Residential Service. Since that time loads have grown and other rates, LC, Large Commercial Rate, LP, Large Industrial Power Rate, etc. have been offered to meet those larger loads. These rates have been allowed to overlap adding to inconsistent price signals.

The GS primary customers were 'grandfathered' in the last rate case. The Companies position is that primary service should have unbundled customer, energy and demand pricing to insure the proper signal is sent to each customer and that the customer responsible for imposing the cost pay that cost. It is proposed that these customers be migrated to the appropriate unbundled rate.

Similarly, the Companies are proposing GS secondary customers be restricted to a much smaller and homogeneous group. This will permit the bundled change to accurately reflect those customers and properly charge customer, energy, and demand costs to new customers above 50 kW. Those larger loads are most accurately billed on unbundled rates.

**LC, Large Commercial Rate, and LP, Large Industrial Power Rate,** are currently available to new loads up to 2,000kW. The proposed rates would allow secondary service from 50 kW to 250 kW, primary service from 0 kW to 250 kW and transmission service on a new service, RTS. (See response to 1b below) Setting these parameters prevents a rate overlap and insures like-customers are billed consistently. Most importantly, rather than limit a billing structure it makes time-of-day pricing available to many more customers since all customers above 250 kW are proposed to be on a time-of-day rate. This affords the customer a greater opportunity to control the monthly billing and sends a more accurate price signal.

**LC-TOD, Large Commercial Time-of-day Rate, and LP-TOD, Large Industrial Time-of-Day Power Rate,** are currently available to new loads above 2,000 kW. The proposed rates would allow secondary and primary service from 250 kW to 50,000 kW. Transmission service would be on a new service, RTS. (See response to 1b below) As noted above this sends the customer a better price signal through a more accurate price signal and affords the customer a greater opportunity to control his monthly billing. The limit of 50,000 kW harmonizes the rate structure with that of Kentucky Utilities Company and encourages examination of the possible need for a special contract for atypical customers above that parameter.

b. Transmission service was eliminated from LP, Large Power Industrial Rate, and LP-TOD, Large Power Time-of-Day Rate. That service for existing and future customers is now offered under RTS, Retail Transmission Service.

Under the current rate structure secondary, primary, and transmission service reflect three rates under a single tariff. This was possible as long as the rate structure for each was similar. Such a format is limiting as far as making structural changes to only one delivery level.

In this case, the Companies believe it is advantageous to go to kVA billing rather than billing on kW. Using kVA sends a more accurate signal to the customer of the cost to provide service to that customer and insures that the customer imposing the cost on the system pays that cost. Such a metering and billing format should be clearer to the customer since it does not require a power factor correction calculation. While kVA metering would also be preferred for secondary and primary delivery levels, it is not practical from a resource standpoint to make a global metering change at one time. Therefore, the transmission customers were separated from the other deliveries and kVA proposed for billing as it is under the companies current LI-TOD, Large Industrial Time-of-Day Service.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 2**

**Responding Witness: Paul W. Thompson / Lonnie E. Bellar**

Q-2. Refer to Volume 4 of 5 of LG&E's application, the Testimony of Victor A. Staffieri ("Staffieri Testimony"), at pages 8 and 9.

a. Page 8 refers to $1.5 million contributed by LG&E's parent company, E.ON U.S. LLC ("E.ON U.S."), to the University of Kentucky to fund research on how to reduce carbon emissions from power plants. It goes on to refer to contributions LG&E and its sister utility, Kentucky Utilities Company ("KU"), have agreed to make to the Carbon Management Research Group and the Kentucky Consortium of Carbon Storage. Identify and describe the criteria used to determine whether these types of research contributions are made by one or more of the utilities or by the parent company.

b. The first full paragraph on page 9 refers to the $25 million pledge LG&E and KU have made to the FutureGen project. Provide the date the pledge was originally made and a schedule showing the amounts paid by calendar year and the account(s) in which recorded, and the amount, if any, of the $25 million pledge that was paid during the test year and the account(s) in which it was recorded. Provide also, the annual amounts anticipated to be paid prospectively.

c. Describe the extent to which the scope of the FutureGen program has changed since the Federal Department of Energy opted not to fund the FutureGen project as originally planned and whether this impacts the level of LG&E's future contributions.

A-2. a. The basic criteria for determining whether the cost of these types research should be borne by the ratepayer is the probability of direct and timely benefits to customers. As an example, in the case of the contribution to the University of Kentucky of $1.5 million the research being supported was in its very early stages and although believed to ultimately be beneficial to ratepayers those benefits were not sufficiently defined at the time of the contribution. Also not as defined in the early 2006 time period when this contribution was being envisioned were the details and prospects of federal $CO_2$ legislation. Thus, this initial $1.5m contribution to the University of Kentucky was recorded in such a way as to not be charged to ratepayers. Please also see the response to Question No. 47 of these data responses.

With the passage of time the details and prospect of federal $CO_2$ legislation have become more defined as have the proposals for research in the areas of Carbon Sequestration and Carbon Storage. With this, the decision was made in 2007 to provide funding to the Carbon Management Research Group and the Kentucky Consortium of Carbon Storage and that the benefits of these efforts would result in direct and timely benefits to customers. These contributions are the subject of and further discussed in Commission's Case No. 2008-00308, *In the Matter of: Joint Application Of Duke Energy Kentucky, Inc., Kentucky Power Company, Kentucky Utilities Company And Louisville Gas And Electric Company For An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities Related To Certain Payments Made To Carbon Management Research Group And The Kentucky Consortium For Carbon Storage.*

b. The date of the original pledge was July 24, 2006. No contributions to FutureGen were made in the test year. All amounts were or will be charged to Account 426, below the net operating income line.

| FutureGen contributions charged to Account 426 | | | |
|---|---|---|---|
| | KU | LG&E | Annual Total |
| 2006 | $ 550,000 | $ 550,000 | $ 1,100,000 |
| 2009 | 1,050,000 | 1,050,000 | 2,100,000 |
| 2010 | 3,550,000 | 3,550,000 | 7,100,000 |
| 2011 | 5,050,000 | 5,050,000 | 10,100,000 |
| 2012 | 2,300,000 | 2,300,000 | 4,600,000 |
| Total | $12,500,000 | $12,500,000 | $25,000,000 |

c. The scope for FutureGen at the Mattoon, Illinois location has not changed. Without U.S. Department of Energy funding, however, the project has been delayed. The FutureGen Alliance is utilizing existing contributions and state grants to maintain a reduced level of work on the project. Additional U.S. Department of Energy funding will be sought, once a new administration is in place in 2009. Any decision about future funding levels will be dependent on future funding commitments.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 3**

**Responding Witness: Paul W. Thompson / Robert M. Conroy**

Q-3. Refer to Volume 4 of 5 of the application, the Testimony of Paul W. Thompson ("Thompson Testimony"), at page 8. Mr. Thompson states that LG&E is mitigating the cost of natural gas transportation costs for its Trimble County combustion turbines by purchasing longer-term firm interstate pipeline transportation capacity.

a. Provide the amount of interstate pipeline transportation capacity that LG&E currently has and the amount of the increased capacity that LG&E purchased as part of its cost mitigation activities.

b. Explain how this additional cost is recovered from ratepayers, i.e., is it passed through as part of the transportation cost recovered through the Gas Supply Clause mechanism or recovered in some other rate?

c. Provide the cost/benefit analysis performed by LG&E on the longer-term pipeline capacity purchased as part of this plan.

A-3. a. The tables below show the quantity of firm natural gas transportation that was purchased for Trimble County combustion turbines under the prior contract and the existing contract.

**Trimble County Firm Gas Transportation Capacity Purchased for CTs (MMBtu/Day)**
**Previous**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 0 | 0 | 92,000 | 92,000 | 92,000 | 50,000 | 0 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 0 | 0 | 92.000 | 92,000 | 92.000 | 75,000 | 0 | 0 | 0 |
| 2010 | 0 | 0 | 0 | 0 | 0 | 92,000 | 92,000 | 92,000 | 0 | 0 | 0 | 0 |
| 2011 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 2012 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Trimble County Firm Gas Transportation Capacity Purchased for CTs (MMBtu/Day)**
**Increase**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 59,000 | 59,000 | 59,000 | 59,000 | 59,000 | 101,000 | 59,000 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 59,000 | 59,000 | 59,000 | 59,000 | 59,000 | 76,000 | 59,000 | 0 | 0 |
| 2010 | 0 | 0 | 0 | 59,000 | 59,000 | 59,000 | 59,000 | 59,000 | 151,000 | 59,000 | 0 | 0 |
| 2011 | 0 | 0 | 0 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151.000 | 0 | 0 |
| 2012 | 0 | 0 | 0 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 0 | 0 |

**Trimble County Firm Gas Transportation Capacity Purchased for CTs (MMBtu/Day)**
**Current**

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 2008 | 0 | 0 | 0 | 59,000 | 59,000 | 151,000 | 151,000 | 151,000 | 151,000 | 59.000 | 0 | 0 |
| 2009 | 0 | 0 | 0 | 59,000 | 59,000 | 151,000 | 151.000 | 151,000 | 151,000 | 59,000 | 0 | 0 |
| 2010 | 0 | 0 | 0 | 59,000 | 59,000 | 151.000 | 151,000 | 151,000 | 151,000 | 59,000 | 0 | 0 |
| 2011 | 0 | 0 | 0 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 0 | 0 |
| 2012 | 0 | 0 | 0 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 151,000 | 0 | 0 |

b. The cost of natural gas transportation for the combustion turbines at Trimble County is included in fuel inventory and recovered through the Fuel Adjustment Clause.

c. The analysis used to determine the benefit of increasing the amount of firm gas transportation at Trimble County was based upon the expected utilization of the Trimble County combustion turbines. Locking in the firm gas transportation at Trimble County under the current contract was least cost ($23 million NPVRR over 5 years) compared to the previous contract. This analysis assumed that natural gas is available only for combustion turbines with firm transportation. The offer from the natural gas transportation company was for the months of April through October. Please see the presentation provided on CD.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 4**

**Responding Witness: Paul W. Thompson**

Q-4. Refer to the Thompson Testimony at page 11.

a. Provide the approximate point in time when LG&E began using thermal-based transmission line ratings, as opposed to seasonal (static) ratings, to measure line capability.

b. Mr. Thompson states that, in his judgment, use of thermal-based line ratings has resulted in a measurable increase in the productivity of the company's assets, which is indicated by a significant decrease in the number of Transmission Line Loading Relief ("TLRs") directives called on LG&E's system since the adoption of thermal-based ratings. Based on the response to part (a) of this request, provide the number of TLRs for LG&E for the three calendar years prior to adoption of the thermal-based approach and for each of the calendar years since the adoption.

A-4. a. Temperature based ratings for both LG&E and KU were fully implemented in the second quarter of 2006.

b. The number of directives called upon for LG&E and KU combined (since they are operated as one transmission system) are as follows.

| Year | Total Events |
|---|---|
| 2001 | 32 |
| 2002 | 147 |
| 2003 | 119 |
| 2004 | 189 |
| 2005 | 265 |
| 2006 | 104 |
| 2007 | 54 |
| 2008 | 29 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 5**

**Responding Witness: Paul W. Thompson**

Q-5. Refer to the Thompson Testimony at page 15. Explain whether the reference on lines 15 to 17 is to Trimble County 2 or to another future base load unit.

A-5. The reference is to another (additional) future base load unit.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 6**

**Responding Witness: Paul W. Thompson**

Q-6. Refer to the Thompson Testimony at page 17, specifically, the reference to the July 2007 Request for Proposals seeking long-term capacity and energy supplies from renewable resources. Based on the more detailed discussions entered into with the short-list developers, when does LG&E expect to make a decision and/or selection for acquiring power from renewable resources?

A-6. The Companies continue to evaluate the proposals. LG&E and KU will inform the Commission in a timely manner once a decision is known.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 7**

**Responding Witness: Chris Hermann**

Q-7. Refer to Volume 4 of 5 of LG&E's application, the Testimony of Chris Hermann ("Hermann Testimony"), at page 7. The testimony refers to the upward trend in duration and frequency of interruptions that were indicated in 2003 and improvements LG&E has seen since making increased investments in reliability, including a new outage management system. Provide LG&E's SAIDI, SAIFI, and CAIDI measurements, on an annual basis, for the years 2003 through 2007.

A-7. The Distribution Reliability report for the Louisville Gas and Electric Company ("LG&E") is based on the calendar year 2007 (January through December). The utility has reported the most recent five years of data including the current year.

The report includes the following:

1. System Average Interruption Duration Index ("SAIDI")
2. System Average Interruption Frequency Index ("SAIFI")
3. Customer Average Interruption Duration Index ("CAIDI")

Pursuant to Commission directive, the Institute of Electrical and Electronic Engineers ("IEEE") standard number IEEE 1366 - 2003 has been used to define the terms in the reliability report, including the criteria for omitting events classified as major event days. The 2007 data is reported by the IEEE exclusion definition. Data is not available based on the IEEE rule prior to 2007. Data for 2006 and earlier is reported on the company's previous 24 hour exclusion rule. The 24 hour exclusion rule was defined as any major event exceeding 24 hours restoration time.

Outages have been measured and reported in minutes.

LG&E completed the installation of a new Outage Management System ("OMS") in November 2004. Because the data collected through the new OMS system is more complete and accurate than previous data collection methods, the new data collected is difficult to compare to the earlier data. This lack of comparability has the effect of showing an increase in SAIDI and SAIFI for 2005 as compared to the previous year.

The data provided herein was submitted in LG&E's 2007 Annual Reliability Report pursuant to the Commission's Order, Administrative Case 2006-00494, dated October 26, 2007.

## Distribution Operations System Reliability
### Louisville Gas and Electric Company

| Louisville Gas and Electric | SAIDI (minutes) | SAIFI | CAIDI (minutes) |
|---|---|---|---|
| 2003 | 84.73 | 0.908 | 93.35 |
| 2004 | 60.46 | 0.810 | 74.67 |
| 2005 | 101.74 | 1.175 | 86.57 |
| 2006 | 86.29 | 1.026 | 84.08 |
| 2007 | 89.65 | 1.116 | 80.35 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 8**

**Responding Witness: Chris Hermann**

Q-8. Refer to page 15 of the Hermann Testimony.

a. Explain whether the Mother Ann Lee hydroelectric power station at Lock & Dam 7 on the Kentucky River is a power station previously owned by KU.

b. What amount of Renewable Energy Certificates, or Green Tags, is available to LG&E from the Mother Ann Lee power station?

A-8. a. The Mother Ann Lee hydroelectric power station is a former KU plant, the Lock No. 7 Hydroelectric Project. KU received Commission approval for the associated transfer of property on December 22, 2005. See *In the Matter of: The Application of Kentucky Utilities Company Regarding The Transfer of Any Real Property Associated with the Lock No. 7 Hydroelectric Project, Project No. 539 to Lock 7 Hydro Partners, LLC,* Case No. 2005-00405. KU received FERC approval for transfer of the license to operate the plant in FERC Docket No. P-539-000 on January 30, 2006.

b. Lock 7 Hydro Partners, LLC, the owner and operator of the Mother Ann Lee hydroelectric power station, sells all of the available Renewable Energy Credits ("RECs") to 3Degrees, a third-party climate solutions vendor. LG&E and KU are under contract with 3Degrees to purchase RECs in proportion to the kWh blocks of Green Energy purchased by KU and LG&E customers. The amount of RECs available from Mother Ann Lee will vary over time based on unit availability and operation. For 2008, LG&E and KU collectively have secured approximately 4,000 RECs year-to-date and expect to secure approximately 7,000 RECs for the calendar year.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 9

Responding Witness: Robert M. Conroy

Q-9. Refer to Volume 4 of 5 of LG&E's application, the Testimony of S. Bradford Rives ("Rives Testimony"), at page 9; the Testimony of Robert M. Conroy ("Conroy Testimony") at page 2; Reference Schedule 1.06 of Exhibit 1 to the Rives Testimony; and Exhibit 1 to the Conroy Testimony.

a. The Rives Testimony refers to the adjustment for the Environmental Cost Recovery ("ECR") "roll-in" into base rates being prepared by Mr. Conroy and being discussed in his testimony. The Conroy Testimony identifies the exhibits which include the adjustment and states that it is consistent with the adjustment in LG&E's previous rate case. As per Conroy Exhibit 1, pages 12-20, explain in detail why the ECR roll-in resulted in reduced rates and revenues for the Industrial Power Time of Day and Special Contract rate classes.

b. The reference schedule shows the amounts of the revenue and expense adjustments related to the ECR roll-in. Provide a detailed explanation for the disparity between the proposed ECR revenue roll-in of $1,215,475 and the proposed ECR expense roll-in of $8,811,442.

A-9. a. The ECR roll-in is calculated for each rate class by dividing the total ECR costs to be collected through base rates by the total revenue collected from each rate class for the most recent 12-month period for which LG&E has revenue data. After the ECR revenue to be collected through base rates has been determined for each rate class, that revenue is then divided by the billing units for which tariff rates will be adjusted. Therefore, for rate classes that are billed a demand charge, the total ECR revenue to be collected from those rate classes is divided by the total billed demand for those rate classes to determine the portion of the demand charge that is associated with collecting ECR revenues through base rates. As a result of this allocation method, when the proportional share of total revenue collected from a particular rate class changes relative to total revenue collected, the proportion of ECR revenue to be collected from that rate class will also change relative to total ECR revenue collected. To the extent that the demand rates for the Industrial Power Time of Day and Special Contract rate classes declined slightly as a result of the ECR roll-in, the decline is indicative of the reduced allocation of ECR costs to those rate classes, relative to the allocation of ECR costs from the previous roll-in case. This has occurred because the ratio of their revenue to total revenue has declined since the prior ECR roll-in occurred.

b. Reference Schedule 1.05 removes total ECR-related expenses from the determination of LG&E's revenue requirement. However, due to the effects of the ECR roll-in, as Ordered by the Commission in Case No. 2007-00380, LG&E's ECR revenues collected through the billing factor will be reduced in part due to the $8,811,442 in expenses incurred during the roll-in period. In effect, LG&E will not be collecting the $8,811,442 through the ECR mechanism, and therefore must reflect the expenses in the determination of its revenue requirement.

Revenue is increased by $1,215,475 to reflect LG&E's anticipated increase in base rate revenues due to the ECR roll-in. LG&E adjusted base rates for the roll-in to collect at total of $25,655,975, of which $23,013,392 was incorporated into base rates through previous roll-ins. Therefore, base rates were adjusted to collect an additional $2,641,636 for the current roll-in. The actual revenue increase is less than the roll-in amount due to over-collections of ECR revenues through base rates during the 12-month period ending December 2007 from the prior ECR roll-in.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 10**

**Responding Witness: S. Bradford Rives**

Q-10. Refer to Volume 4 of 5 of LG&E's application at page 17 of the Rives Testimony concerning the cost of the letter of credit bank fees associated with the new credit facilities LG&E will require, and Reference Schedule 1.32 of Exhibit 1 to the Rives Testimony.

a. The text beginning on Line 21 of page 17 indicates that the fees are based on "a proposal by a bank willing to provide a portion of these facilities under current market conditions." Provide the number of financial institutions from which LG&E solicited proposals for the new credit facilities, the number of proposals LG&E received and the reasons why the proposal in question was chosen by LG&E.

b. Provide a copy of all the proposals received by LG&E along with any supporting workpapers and related documents that show the derivation of the $2.5 million amount shown in the exhibit as the cost of the new credit facilities.

A-10. a. This information is being filed pursuant to a Petition for Confidential Protection.

b. This information is being filed pursuant to a Petition for Confidential Protection.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 11**

**Responding Witness: S. Bradford Rives**

Q-11. Refer to page 21 of the Rives Testimony. Mr. Rives states that LG&E has a target capital structure of the midpoint of the range for an "A" rating as published by Standard and Poor's. Provide LG&E's current rating.

A-11. LG&E's long-term credit rating from S&P is BBB+ and the short-term rating is A-2. LG&E's issuer rating from Moody's is A2 and the commercial paper rating is P-1.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 12**

**Responding Witness: Robert M. Conroy**

Q-12. Refer to page 29 of the Rives Testimony, specifically, the discussion of the Mill Creek Ash Dredging Regulatory Asset, and Appendix B, Exhibit 3 to the Rives Testimony. The reference to the Commission's Order in Case No. 2004-00421 reflects that the Commission found that it would "include the unamortized balance of the deferred costs in the environmental rate base." Explain in detail why LG&E now proposes to include the unamortized balance in its rate base in this base rate case.

A-12. The Mill Creek Ash Dredging regulatory asset remains part of the environmental surcharge mechanism as approved by the Commission's Order in Case No. 2004-00421; however, the Commission's Order dated March 28, 2008 in Case No. 2007-00380 approved the roll-in of environmental surcharge amounts into base rates which included the Mill Creek Ash Dredging deferred debit in the amount of $2,134,844. This amount is included in existing base rates and rate base.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 13**

**Responding Witness: S. Bradford Rives**

Q-13. Refer to Volume 4 of 5 of LG&E's application, the Direct Testimony of William E. Avera ("Avera Testimony"), at pages 9-10.

a. To the extent that LG&E's capital requirements are satisfied through its parent company, E.ON AG ("E.ON") explain how E.ON and ultimately LG&E actually obtain this capital.

b. Describe the role that LG&E's credit ratings from Fitch and Standard and Poor's plays in LG&E obtaining capital from its parent.

c. To the extent that LG&E issues tax exempt debt securities to satisfy its capital needs, describe the role that LG&E's credit ratings from Fitch and Standard and Poor's plays in the issuance of this debt.

d. To the extent that LG&E issues tax exempt debt, explain whether E.ON or any subsidiary of E.ON other than LG&E is liable in any way for repayment.

e. To the extent that LG&E issues tax exempt debt, explain how LG&E is able to issue this type of debt and how the issuance actually occurs.

A-13. a. E.ON AG raises capital through three sources. First, a portion of earnings is retained and made available for investment in E.ON's business. Second, E.ON AG is an active issuer of debt in worldwide capital markets. Third, E.ON AG could elect to issue additional shares of equity. E.ON makes proceeds of these sources available to its subsidiary companies. In the case of LG&E, funds are provided by E.ON AG in two ways. First, Fidelia (another wholly owned subsidiary of E.ON AG) loans funds to LG&E as described in b. below. Second, E.ON U.S. has, from time to time, contributed funds to LG&E as equity. The levels of debt and equity are managed to remain in the ranges recommended by Standard and Poor's for an 'A' rated utility.

b. LG&E does not subscribe to ratings from Fitch, therefore Fitch plays no role in the issuance of tax exempt debt securities for LG&E. LG&E is currently rated BBB+ by Standard and Poor's and A2 by Moody's. The Order obtained from the Commission for Case No. 2007-00550 indicates that interest rates on borrowings from Fidelia are to be determined using the "Best Rate Method". The Best Rate Method assures the Company that it will not pay more for a loan from Fidelia than it would pay in the capital markets for a similar loan. The interest rate on each note is determined by the lower of (a) the average of three quotes obtained by the affiliate company (E.ON AG) from international investment banks for an unsecured bond issued by E.ON for the applicable term of the loan; and (b) the lowest of three quotes obtained by LG&E from international investment banks for a secured bond issued by LG&E with the applicable term of the loan. This method complies with the Best Rate Method because the rate is determined using the lower of the average of actual quotes obtained based on the credit of E.ON or the lowest of three actual quotes obtained by LG&E. International banks providing the quotes mentioned above use the credit ratings from S&P and Moody's for LG&E in determining the rate of interest to be quoted on a secured bond that would be issued by LG&E.

c. LG&E does not subscribe to ratings from Fitch, therefore Fitch plays no role in the issuance of tax-exempt debt securities for LG&E. LG&E is currently rated BBB+ by Standard and Poor's and A2 by Moody's. The credit rating from Standard and Poor's and Moody's impacts the interest rate the Company pays to the tax-exempt bondholder. (The higher the credit rating, the lower the interest rate). For tax-exempt issues with a credit facility or bond insurance, the credit rating from Standard and Poor's and Moody's impacts the cost of the credit enhancement. (The higher the credit rating, the lower the cost of the enhancement).

d. Neither E.ON nor any subsidiary of E.ON other than LG&E is liable in any way for repayment.

e. The Kentucky Private Activity Bond Allocation Committee is established by KRS 103.210, with membership comprised of the Secretary of the Finance and Administration Cabinet (Chair), Secretary of the Cabinet for Economic Development, State Budget Director, State Controller, and Secretary of the Governor's Executive Cabinet, or their designees. The purpose of the Committee is to ensure that "private activity bonds" issued by the Commonwealth, its political subdivisions, and other authorized issuers within the Commonwealth, comply with the state ceiling (allocated to each state based on population) imposed by the Tax Reform Act of 1986, 26 U.S.C. Section 146.

   "Private Activity Bonds" are defined in 26 U.S.C. Section 141. In brief, Private Activity Bonds are bonds issued by a governmental issuer, but proceeds from which are used for a "qualified private business" use, which is beneficial to the public, such as airports, water facilities, solid waste disposal facilities, etc. The bonds would be issued by the respective county, and the proceeds then loaned to LG&E in connection with financing portions of LG&E's projects.

Under 26 U.S.C. Section 142, (and subject to various limitations) these bonds qualify as "Exempt Facility Bonds," which may be issued as tax-exempt debt, if used to finance, among other things, solid waste disposal facilities. The proceeds from the Bonds to be issued by the county would be used to provide permanent financing for portions of LG&E's pollution control project which qualify as solid waste disposal facilities. The county's actions are authorized by KRS 103.210 which provides for issuance of such bonds for various purposes, including defraying the costs of pollution control. LG&E's financing of its pollution control project qualifies as a private business use under 26 U.S.C. Section 141, and because the proceeds will be used to finance Exempt Facilities, LG&E is entitled to apply for and receive an allocation from the Committee.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 14**

**Responding Witness: Robert M. Conroy**

Q-14. Refer to page 14 of the Avera Testimony. Explain whether LG&E has requested that the Commission alter its Fuel Adjustment Clause and Gas Cost Adjustment mechanisms in order to recover costs in a more timely fashion and alleviate investor concerns regarding the lag between when expenses are incurred and when they are recovered through rates.

A-14. LG&E has not requested that the Commission alter the fuel adjustment clause or gas cost adjustment mechanisms.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 15**

**Responding Witness: William E. Avera**

Q-15. Refer to pages 15-16 of the Avera Testimony.

a. Kentucky is not a restructured state. Describe how investors' views of utilities differ between restructured and traditionally regulated states.

b. Explain whether this Commission has acted in any way that would give investors reason to doubt that LG&E would be able to recover its costs in a timely fashion or in a manner that would lead investors to view the Kentucky regulatory environment as hostile.

A-15. a. Dr. Avera's testimony at pages 15-16 discussed restructuring for wholesale transmission operations under the jurisdiction of the Federal Energy Regulatory Commission (FERC) and did not pertain to retail restructuring at the state level. Thus, investors' views of differences between restructured and traditionally regulated states are not relevant to Dr. Avera's evaluation or his testimony at pages 15-16.

b. Dr. Avera's testimony at pages 15-16 discusses the increased complexity of wholesale transmission operations and the associated risks. While Dr. Avera's testimony noted that regulatory risks are an important factor considered by investors in their forward-looking evaluation of utilities, he did not state or imply that the KPSC has acted in a manner that would lead investors to view the regulatory environment as hostile. In fact, as Dr. Avera testified, he believes Kentucky has a balanced regulatory environment.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 16**

**Responding Witness: William E. Avera**

Q-16. Refer to pages 17-18 of the Avera Testimony. Provide a copy of Moody's Investors Service, "Credit Opinion: Louisville Gas & Electric Co.," referenced in footnote 34.

Refer to page 24 of the Avera Testimony and Schedule WEA-1. Provide a schedule which lists each of the 17 utilities in the Utility Proxy Group plus LG&E as #18 and which shows the following information for each utility: 2007 total revenue; 2007 electric revenue; 2007 gas revenue; total utility customers served; electric customers served; gas customers served; nuclear generation as a percent of total generating capacity; whether the utility operates in traditionally regulated states or restructured states; the debt-to-equity ratio; whether the utility has a rate mechanism to track changes in fuel costs, and if so, the timeliness of the tracking; and whether the utility has a rate mechanism to track environmental costs, and if so, the timeliness of the tracking.

A-16. A copy of the requested document from Moody's Investors Service is included in Dr. Avera's work papers provided in response to the AG-1 Question No. 89 at WEA-WP45.

The information requested is not readily available. The Company is compiling the data that it can obtain and will provide such data in a supplemental response to this question.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 17**

**Responding Witness: William E. Avera**

Q-17. Provide the most current Value Line profile sheet for LG&E and for each of the 17 utilities listed in Mr. Avera's Utility Proxy Group.

A-17. Because it is a wholly owned subsidiary of E.ON U.S. LLC, which in turn is an indirect subsidiary of E.ON AG, Value Line does not publish an Investment Survey report for LG&E. The most recent Value Line Investment Survey reports for each of the firms in the Utility Proxy Group are attached.

# ALLETE NYSE-ALE

RECENT PRICE 45.15 | P/E RATIO 15.8 (Trailing: 15.2; Median: NMF) | RELATIVE P/E RATIO 0.97 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 3 Lowered 11/2/07
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 6/13/08
BETA .90 (1.00 = Market)

**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+35%) | 11% |
| Low | 45 | (Nil) | 4% |

**Insider Decisions**

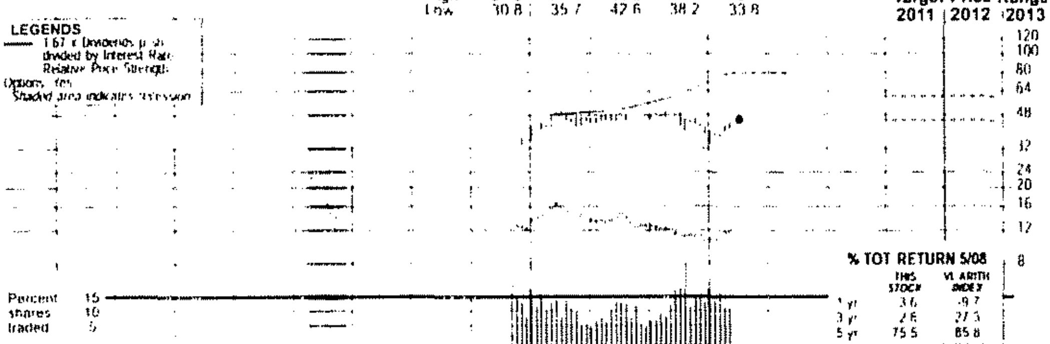
| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Options | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 80 | 83 | 62 |
| to Sell | 71 | 75 | 86 |
| Hld's(000) | 19001 | 18543 | 18034 |

| | | | | | |
|---|---|---|---|---|---|
| High | 37.5 | 51.7 | 49.3 | 51.3 | 46.1 |
| Low | 30.8 | 35.7 | 42.6 | 38.2 | 33.8 |

Target Price Range 2011 2012 2013




% TOT. RETURN 5/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 3.6 | -9.7 |
| 3 yr. | 2.6 | 27.3 |
| 5 yr. | 75.5 | 85.8 |

ALLETE in its current configuration began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

| 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|
| 25.30 | 24.50 | 25.23 | 27.33 | 26.45 | 26.65 | Revenues per sh | 27.75 |
| 2.97 | 3.85 | 4.14 | 4.42 | 4.15 | 4.35 | "Cash Flow" per sh | 5.25 |
| 1.35 | 2.48 | 2.77 | 3.08 | 2.85 | 2.95 | Earnings per sh A | 3.25 |
| .30 | 1.25 | 1.45 | 1.64 | 1.72 | 1.80 | Div'd Decl'd per sh B ■ † | 2.00 |
| 2.12 | 1.95 | 3.37 | 6.82 | 9.80 | 11.30 | Cap'l Spending per sh | 7.00 |
| 21.23 | 20.03 | 21.90 | 24.11 | 25.60 | 27.10 | Book Value per sh C | 32.50 |
| 29.70 | 30.10 | 30.40 | 30.80 | 32.30 | 33.60 | Common Shs Outst'g D | 36.50 |
| 25.2 | 17.9 | 16.5 | 14.6 | Bold figures are | | Avg Ann'l P/E Ratio | 15.5 |
| 1.33 | .95 | .89 | .78 | Value Line | | Relative P/E Ratio | 1.05 |
| .9% | 2.8% | 3.2% | 3.6% | estimates | | Avg Ann'l Div'd Yield | 4.0% |
| 751.4 | 737.4 | 767.1 | 841.7 | 855 | 895 | Revenues ($mill) | 1015 |
| 38.5 | 68.0 | 77.3 | 87.6 | 85.0 | 90.0 | Net Profit ($mill) | 110 |
| 38.8% | 28.4% | 37.5% | 34.8% | 38.0% | 38.0% | Income Tax Rate | 38.0% |
| 1.8% | 4% | 8% | 2.3% | 6.0% | 7.0% | AFUDC % to Net Profit | 3.0% |
| 38.2% | 39.1% | 35.1% | 35.6% | 41.0% | 42.5% | Long-Term Debt Ratio | 46.0% |
| 61.8% | 60.9% | 64.9% | 64.4% | 59.0% | 57.5% | Common Equity Ratio | 54.0% |
| 1020.7 | 990.6 | 1025.6 | 1153.5 | 1400 | 1600 | Total Capital ($mill) | 2200 |
| 883.1 | 860.4 | 921.6 | 1104.5 | 1370 | 1695 | Net Plant ($mill) | 2325 |
| 5.1% | 8.0% | 8.6% | 8.6% | 7.0% | 7.0% | Return on Total Cap'l | 6.5% |
| 6.1% | 11.3% | 11.6% | 11.8% | 10.0% | 10.0% | Return on Shr. Equity | 9.5% |
| 6.1% | 11.3% | 11.6% | 11.8% | 10.0% | 10.0% | Return on Com Equity E | 9.5% |
| 4.7% | 5.2% | 5.0% | 5.8% | 3.5% | 3.5% | Retained to Com Eq | 3.5% |
| 23% | 54% | 57% | 51% | 65% | 65% | All Div'ds to Net Prof | 64% |

**CAPITAL STRUCTURE as of 3/31/08**
Total Debt $483.1 mill. Due in 5 Yrs $33.0 mill.
LT Debt $470.3 mill. LT Interest $25.2 mill.
(LT interest earned: 6.5x)
Leases, Uncapitalized Annual rentals $8.1 mill.

Pension Assets-12/07 $405.6 mill. Oblig. $420.4 mill.

Pfd Stock None

Common Stock 30,841,376 shs.
as of 4/30/08

**MARKET CAP: $1.4 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.0 | +1.1 | +.5 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 3.93 | 4.15 | 4.82 |
| Capacity at Peak (Mw) | 1512 | 1761 | 1701 |
| Peak Load, Winter (Mw) | 1543 | 1586 | 1614 |
| Annual Load Factor (%) | 80.0 | 80.0 | 80.0 |
| % Change Customers (avg.) | +1.1 | +1.3 | +1.3 |
| Fixed Charge Cov. (%) | 461 | 503 | 503 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | -- | -- | 1.5% |
| "Cash Flow" | -- | -- | 4.0% |
| Earnings | -- | -- | 2.5% |
| Dividends | -- | -- | 5.5% |
| Book Value | -- | -- | 6.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 193.3 | 174.4 | 177.4 | 192.3 | 737.4 |
| 2006 | 192.5 | 178.3 | 199.1 | 197.2 | 767.1 |
| 2007 | 205.3 | 223.3 | 200.8 | 212.3 | 841.7 |
| 2008 | 213.4 | 211.6 | 215 | 215 | 855 |
| 2009 | 225 | 220 | 225 | 225 | 895 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .64 | .38 | .58 | .88 | 2.48 |
| 2006 | .68 | .49 | .78 | .82 | 2.77 |
| 2007 | .93 | .80 | .58 | .77 | 3.08 |
| 2008 | .82 | .63 | .70 | .70 | 2.85 |
| 2009 | .85 | .60 | .75 | .75 | 2.95 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | | | -- | .30 | .30 |
| 2005 | .30 | .315 | .315 | .315 | 1.25 |
| 2006 | .363 | .363 | .363 | .363 | 1.45 |
| 2007 | .41 | .41 | .41 | .41 | 1.64 |
| 2008 | .43 | .43 | | | |

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 141,000 customers in northeastern Minn., and Superior Water, Light & Power in northwestern Wisc. Electric revenue mix '07: taconite mining/processing, 28%; paper/wood products, 11%; other industrial, 8%; residential, 12%; commercial, 13%; wholesale, 13%; other, 15%. Has real estate operation in Florida. Discontinued water-utility ops. in '01. Spun off automotive remarketing ops. (ADESA) in '04. Generating sources '07: coal & lignite, 62%; hydro, 3%; purchased, 35%. '07 deprec. rate: 2.5%. Has 1,500 employees. Chairman, President & CEO: Donald J. Shippar. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

**ALLETE's utility subsidiary has filed a general rate case.** Minnesota Power's first such filing in 14 years seeks a tariff increase of $45 million (9.5%) based on an 11.15% return on a common-equity ratio of 54.8%. The utility is asking for an interim rate increase of $36 million (8%) to take effect in mid-2008. This includes $8 million that is already being recovered through rate riders, so the net effect on revenues in the second half of the year would be $14 million. The final order is due in mid-2009.
**A wholesale rate hike took effect on March 1st.** The Federal Energy Regulatory Commission granted Minnesota Power an increase of $7.5 million, based on an 11.25% return on a 59% common-equity ratio.
**Minnesota Power's heavy capital program will require additional rate cases.** The utility plans to spend over $1.5 billion from 2008 through 2012. About half of this spending will be for environmental and renewable-energy projects that are recoverable through rate riders until they are rolled into base tariffs through a general rate application.
**This year, a sharp decline in real estate income will outweigh the expected increase in utility profits.** ALLETE is finally feeling the effects of the real estate slump in Florida, which has hurt the developers that buy property from the company. The company's earnings guidance for 2008 is $2.70-$2.90 a share, and even the upper end would be a 6% decline from the 2007 tally. (We've raised our estimate by $0.15 a share, to $2.85, due to ALLETE's better-than-expected March-quarter earnings.) The earnings growth we forecast for 2009 assumes a rise in utility income but no improvement in real estate. Even so, the company's real estate operation is well positioned to ride out the current turmoil, since it has very little debt and the market value of its land is well above the $63.1 million book value.
**This stock is up over 15% since our late-March report.** We think that this was a correction after investors overreacted to the disappointing prospects for ALLETE's real estate business. At the current quotation, the stock is fairly valued compared with the typical utility equity.
*Paul E. Debbas, CFA* *June 27, 2008*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢ net; '05, ($1.84); gain (losses) on discontinued operations: '04, $2.57; '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next earnings report due late July. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '07: $2.49/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '95: 11.6%; earned on avg. com. eq., '07: 12.4%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | NMF |
| Earnings Predictability | NMF |

# ALLIANT ENERGY NYSE-LNT

RECENT PRICE **37.06** | P/E RATIO **13.5** (Trailing 13.5 Median 14.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **3.9%** | **VALUE LINE**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 34.4 | 34.9 | 32.4 | 37.8 | 33.2 | 31.0 | 25.1 | 28.8 | 30.6 | 40.0 | 46.5 | 42.4 |
| Low | 26.8 | 28.0 | 25.2 | 25.6 | 27.5 | 14.3 | 15.0 | 23.5 | 25.6 | 27.5 | 34.9 | 34.0 |

**TIMELINESS** 3 Raised 2/15/08
**SAFETY** 2 Raised 9/28/07
**TECHNICAL** 3 Lowered 5/30/08
**BETA** .90 (1.00 = Market)

**2011-13 PROJECTIONS**

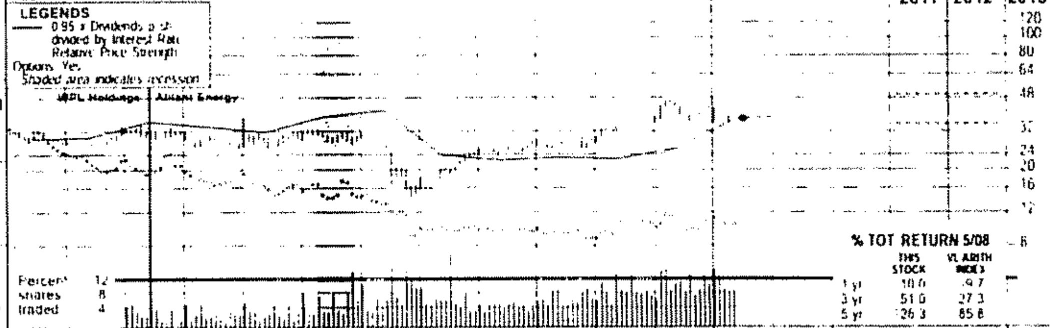
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+35%) | 11% |
| Low | 35 | (-5%) | 3% |

**Insider Decisions**

| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 92 | 116 | 122 |
| to Sell | 146 | 108 | 115 |
| Hld's(000) | 62642 | 63027 | 63707 |




**% TOT. RETURN 5/08**

| | THIS STOCK | VL ARITH INDEX |
|---|---|---|
| 1 yr | 10.0 | -9.7 |
| 3 yr | 51.0 | 27.3 |
| 5 yr | 126.3 | 85.8 |

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share. IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share. Data prior to 1998 are for WPL Holdings only and are not comparable with Alliant Energy data.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 27.45 | 27.83 | 30.44 | 30.97 | 28.26 | 28.19 | 25.56 | 28.02 | 28.93 | 31.15 | **33.25** | **34.75** | Revenues per sh | **27.80** |
| 4.85 | 5.71 | 6.57 | 5.52 | 4.52 | 4.19 | 4.69 | 5.46 | 4.33 | 5.12 | **5.55** | **6.10** | "Cash Flow" per sh | **7.55** |
| 1.26 | 2.19 | 2.47 | 2.47 | 1.15 | 1.57 | 1.85 | 2.21 | 2.06 | 2.69 | **2.75** | **2.90** | Earnings per sh A | **3.30** |
| 2.00 | 2.00 | 2.00 | 2.00 | 2.00 | 1.00 | 1.02 | 1.05 | 1.15 | 1.27 | **1.40** | **1.53** | Div'd Decl'd per sh B ■ † | **1.97** |
| 4.79 | 6.06 | 13.50 | 9.13 | 7.12 | 7.69 | 5.55 | 4.51 | 3.42 | 4.91 | **9.45** | **11.00** | Cap'l Spending per sh | **5.90** |
| 20.69 | 27.29 | 25.79 | 21.39 | 19.89 | 21.37 | 22.13 | 20.65 | 22.83 | 24.30 | **25.75** | **27.15** | Book Value per sh C | **31.95** |
| 77.63 | 78.98 | 79.01 | 89.68 | 92.30 | 110.96 | 115.74 | 117.04 | 116.13 | 110.36 | **111.00** | **112.00** | Common Shs Outst'g D | **119.00** |
| 25.1 | 13.0 | 11.6 | 12.6 | 19.5 | 12.7 | 14.5 | 12.6 | 16.8 | 15.1 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | **13.0** |
| 1.31 | .74 | .77 | .65 | 1.09 | .72 | .74 | .67 | .91 | .80 | | | Relative P/E Ratio | **.85** |
| 6.3% | 7.0% | 6.9% | 6.6% | 8.5% | 5.0% | 3.9% | 3.8% | 3.3% | 3.1% | | | Avg Ann'l Div'd Yield | **4.4%** |
| 2130.9 | 2198.0 | 2405.0 | 2777.3 | 2608.8 | 3128.2 | 2958.7 | 3279.6 | 3359.4 | 3437.6 | **3690** | **3890** | Revenues ($mill) | **4500** |
| 103.4 | 178.2 | 203.1 | 194.9 | 111.1 | 176.6 | 229.5 | 337.8 | 260.1 | 320.8 | **325** | **340** | Net Profit ($mill) | **410** |
| 36.0% | 40.3% | 54.0% | 23.5% | 24.2% | 28.9% | 26.7% | 19.0% | 43.8% | 44.4% | **44.0%** | **44.0%** | Income Tax Rate | **44.0%** |
| 6.6% | 4.1% | 4.3% | 5.7% | 6.8% | 11.7% | 6.1% | 3.0% | 3.1% | 2.4% | **3.0%** | **3.0%** | AFUDC % to Net Profit | **3.0%** |
| 47.3% | 39.6% | 47.0% | 54.7% | 56.4% | 44.8% | 45.0% | 41.6% | 31.4% | 32.4% | **36.5%** | **40.0%** | Long-Term Debt Ratio | **41.0%** |
| 49.2% | 57.4% | 50.2% | 42.7% | 39.2% | 50.0% | 50.2% | 53.1% | 62.9% | 61.9% | **58.5%** | **55.5%** | Common Equity Ratio | **55.5%** |
| 3262.9 | 3756.0 | 4061.4 | 4490.2 | 4679.1 | 4738.4 | 5104.7 | 4599.1 | 4218.4 | 4329.5 | **4905** | **5485** | Total Capital ($mill) | **6850** |
| 3101.7 | 3486.0 | 3719.3 | 3862.8 | 3729.2 | 4432.6 | 5284.6 | 4866.2 | 4944.9 | 4679.9 | **5420** | **6290** | Net Plant ($mill) | **8380** |
| 4.9% | 6.1% | 6.6% | 6.2% | 4.1% | 5.7% | 6.1% | 8.9% | 7.5% | 8.6% | **8.0%** | **7.5%** | Return on Total Cap'l | **7.5%** |
| 6.0% | 7.9% | 9.4% | 9.6% | 5.5% | 6.8% | 8.2% | 12.6% | 9.0% | 11.0% | **10.5%** | **10.5%** | Return on Shr. Equity | **9.5%** |
| 6.0% | 8.0% | 9.6% | 9.8% | 5.8% | 6.7% | 8.2% | 13.1% | 9.1% | 11.3% | **11.5%** | **10.5%** | Return on Com Equity E | **10.0%** |
| NMF | 7% | 1.9% | 1.6% | NMF | 2.5% | 3.8% | 8.1% | 4.0% | 5.9% | **5.0%** | **5.0%** | Retained to Com Eq | **4.5%** |
| NMF | 92% | 81% | 85% | NMF | 67% | 58% | 42% | 59% | 50% | **54%** | **55%** | All Div'ds to Net Prof | **60%** |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $1626.7 mill. **Due in 5 Yrs** $555.1 mill.
**LT Debt** $1403.6 mill. **LT Interest** $99.0 mill.
(LT interest earned: 5.8x)
**Pension Assets-12/07** $890.0 mill. **Oblig.** $879.0 mill.
**Pfd Stock** $243.8 mill. **Pfd Div'd** $18.7 mill.
449,765 shs. $100 par; 8,199,460 shs. $25 par; 1,127,787 shs. $50 par.

**Common Stock** 110,436,824 shs.
**MARKET CAP: $4.1 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +4.6 | -1.7 | +1.8 |
| Avg. Indust. Use (MWH) | 4215 | 4180 | 4282 |
| Avg. Indust. Revs. per KWH (¢) | 5.26 | 5.96 | 5.77 |
| Capacity at Peak (Mw) | 5446 | 4985 | 4902 |
| Peak Load, Summer (Mw) | 5932 | 5987 | 5751 |
| Annual Load Factor (%) | 55.6 | 52.0 | 53.0 |
| % Change Customers (yr-end) | +1.3 | +1.8 | -1.8 |
| Fixed Charge Cov. (%) | 252 | 350 | 416 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | -- | .5% | 4.5% |
| "Cash Flow" | 5% | 2.5% | 7.0% |
| Earnings | 5% | 3.0% | 6.0% |
| Dividends | 5.0% | -10.5% | 9.0% |
| Book Value | 1.5% | .5% | 6.0% |

| Calendar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 825.2 | 686.7 | 860.9 | 906.8 | 3279.6 |
| 2006 | 930.9 | 695.8 | 890.4 | 841.3 | 3359.4 |
| 2007 | 912.7 | 746.2 | 907.3 | 871.4 | 3437.6 |
| 2008 | 992.0 | *800* | *970* | *928* | *3690* |
| 2009 | *1040* | *850* | *1020* | *980* | *3890* |

| Calendar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .23 | .41 | 1.05 | .52 | 2.21 |
| 2006 | .56 | .39 | .75 | .36 | 2.06 |
| 2007 | .56 | .43 | 1.05 | .65 | 2.69 |
| 2008 | .62 | *.45* | *1.05* | *.63* | *2.75* |
| 2009 | *.65* | *.48* | *1.10* | *.67* | *2.90* |

| Calendar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .25 | .25 | .25 | .263 | 1.01 |
| 2005 | .263 | .263 | .263 | .263 | 1.05 |
| 2006 | .288 | .288 | .288 | .288 | 1.15 |
| 2007 | .318 | .318 | .318 | .318 | 1.27 |
| 2008 | .35 | .35 | | | |

**BUSINESS:** Alliant Energy, formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies elect. (73% of revs.), gas (19%), and other services (8%) in Wisconsin, Iowa, Minnesota, & Illinois. Elect. revs. by state: WI, 47%; IA, 49%; MN, 3%; IL, 1%. Elect. rev.: resid., 35%; comm'l, 22%; ind'l, 30%; wholesale, 7%; other, 6%. Fuel sources, '07: coal, 65%; gas, 28%; oil, 6%; other, under 1%. Fuel costs: 54% of revs. '07 deprec. rate: 2.6%. Est'd plant age: 10 yrs. Has 5,179 empls. Chrmn.: Erroll B. Davis, Jr. Pres. & CEO: William D. Harvey. Inc.: WI. Address: 4902 N. Biltmore Lane, P.O. Box 77007, Madison, WI 53707-1007. Tel.: 608-458-3391. Internet: www.alliant-energy.com.

**Alliant Energy's Iowa operations were seriously disrupted by extreme flooding in mid-June.** Three generating stations totaling 380 megawatts of capacity were forced offline. Too, customers receiving 280 megawatts (mw) of load have been unable to take electric service, and it's uncertain when they will be able to do so. Rail and barge coal deliveries continue to experience disruptions, and 14 substations in the hard-hit Cedar Rapids area have been flooded. To ease the financial impact, LNT has insurance with total limits of $100 million for covered flood losses and is evaluating regulatory options for recovery. In addition, incremental costs of replacement power needs should flow through LNT's energy adjustment clauses. At this time, management is unable to predict the flood's impact on 2008 earnings. The damage is not expected to have a material long-term adverse effect on profits.

**The company awaits an order on its filing for higher rates in Wisconsin.** It seeks a $93 million hike in retail electric rates and a nominal $1 million decrease in posted natural gas tariffs. Cost drivers on the electric side include increased spending on the generation infrastructure, environmental compliance, and investments in renewable energy. The small reduction in gas rates reflects lower costs forecast for 2009 and 2010. Whatever amount is awarded will take effect next January 1st. Separately, LNT received regulatory approval to discontinue customer credits of $26 million related to decommissioning funds from the sale of the Kewaunee Wisconsin nuclear plant.

**Our 2008 earnings estimate should be regarded as tentative.** We won't take into account the effect of flooding or the amount of likely damage recovery until both are better known. For now, we estimate 2008 earnings will rise a nominal 2%, to $2.75 a share. An order on the aforementioned rate request suggests improvement next year.

**The stock might interest income-oriented utility investors.** A low payout ratio, coupled with our forecast of slow but steady earnings gains to 2011-2013, indicates above-average dividend growth over the same time frame. What's more, finances are strong.

*Arthur H. Medalie* *June 27, 2008*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '96, net 7¢; '99, 32¢; '00, $2.56; '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 84¢; '07, $1.11. Next egs. rpt. due late July. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. deferred chgs. in '07: $307.9 mill., $2.79/sh. (D) In mill. (E) Rate base: Orig. cost. Rate allowed on com. eq. in '05: WI, 10.8%; in '07, IA, 10.7%; earned on avg. com. eq., '07: 11.3%. Regul. Clim.: WI, Above Avg.; IA, Below Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 30 |
| Earnings Predictability | 65 |

# CON. EDISON NYSE-ED

RECENT PRICE 41.01 | P/E RATIO 13.5 (Trailing: 12.8 Median: 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 5.7% | VALUE LINE

TIMELINESS 3 Raised 8/11/06
SAFETY 1 New 7/27/90
TECHNICAL 3 Raised 8/3/06
BETA .75 (1.00 = Market)

**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+20%) | 10% |
| Low | 40 | (Nil) | 5% |

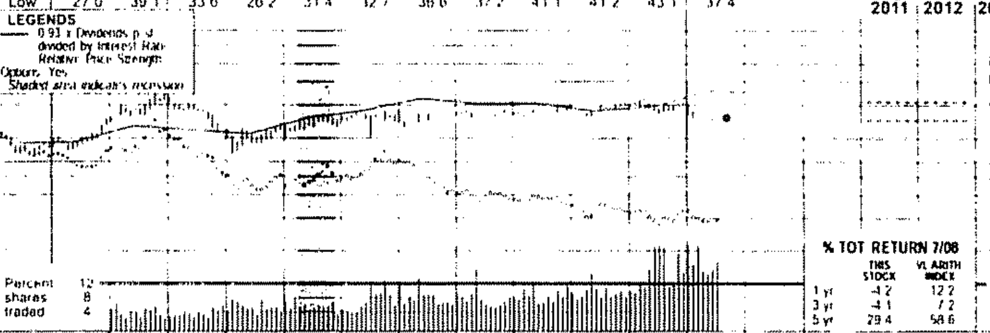
**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 1 | 2 | 0 | 0 | 1 | 0 | 0 | 1 |
| Options | 1 | 2 | 3 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 1 | 2 | 3 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 162 | 224 | 183 |
| to Sell | 196 | 142 | 203 |
| Hld's(000) | 142085 | 133242 | 127910 |

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 41.5 | 56.1 | 53.4 | 39.5 | 43.4 | 45.4 | 46.0 | 45.6 | 49.3 | 49.3 | 52.9 | 49.3 |
| Low | 27.0 | 39.1 | 33.6 | 26.2 | 31.4 | 32.7 | 36.6 | 37.2 | 41.1 | 41.2 | 43.1 | 37.4 |




Target Price Range 2011 | 2012 | 2013

**% TOT. RETURN 7/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -4.2 | 12.2 |
| 3 yr. | -4.1 | 7.2 |
| 5 yr. | 29.4 | 58.6 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25.36 | 26.73 | 27.13 | 27.82 | 29.62 | 30.24 | 30.46 | 35.04 | 44.48 | 45.41 | 39.65 | 43.51 | 40.24 | 47.66 | 47.14 | 48.23 | 40.45 | 51.95 | Revenues per sh | 58.25 |
| 4.06 | 4.36 | 4.77 | 4.87 | 4.97 | 5.08 | 5.29 | 5.74 | 5.51 | 5.70 | 5.44 | 5.12 | 4.54 | 5.27 | 5.28 | 5.77 | 5.80 | 6.15 | "Cash Flow" per sh | 7.30 |
| 2.46 | 2.66 | 2.98 | 2.93 | 2.93 | 2.95 | 3.04 | 3.13 | 2.74 | 3.21 | 3.13 | 2.83 | 2.32 | 2.99 | 2.95 | 3.48 | 3.05 | 3.15 | Earnings per sh A | 3.30 |
| 1.90 | 1.94 | 2.00 | 2.04 | 2.08 | 2.10 | 2.12 | 2.14 | 2.16 | 2.20 | 2.22 | 2.24 | 2.26 | 2.28 | 2.30 | 2.32 | 2.34 | 2.36 | Div'd Decl'd per sh B ■ | 2.42 |
| 3.40 | 3.37 | 3.22 | 2.95 | 2.87 | 2.78 | 2.66 | 3.17 | 4.52 | 5.20 | 5.68 | 5.72 | 5.60 | 6.59 | 7.17 | 7.09 | 9.85 | 9.55 | Cap'l Spending per sh | 6.95 |
| 20.89 | 21.63 | 22.62 | 23.51 | 24.37 | 25.18 | 25.88 | 25.31 | 25.61 | 26.71 | 27.68 | 28.44 | 29.09 | 29.80 | 31.09 | 32.58 | 34.20 | 34.85 | Book Value per sh C | 37.70 |
| 233.93 | 234.37 | 234.91 | 234.96 | 234.99 | 235.49 | 232.83 | 213.81 | 212.03 | 212.15 | 213.93 | 225.84 | 242.51 | 245.29 | 257.46 | 272.02 | 274.00 | 278.00 | Common Shs Outst'g | 284.00 |
| 11.9 | 13.1 | 9.3 | 9.8 | 10.1 | 10.9 | 15.3 | 14.0 | 12.0 | 12.0 | 13.3 | 14.3 | 18.2 | 15.1 | 15.5 | 13.8 | Bold figures are | | Avg Ann'l P/E Ratio | 13.5 |
| .72 | .77 | .61 | .66 | .63 | .63 | .80 | .80 | .78 | .61 | .73 | .82 | .96 | .80 | .84 | .72 | Value Line | | Relative P/E Ratio | .90 |
| 6.5% | 5.6% | 7.2% | 7.1% | 7.0% | 6.5% | 4.6% | 4.9% | 6.6% | 5.7% | 5.3% | 5.5% | 5.3% | 5.0% | 5.0% | 4.8% | estimates | | Avg Ann'l Div'd Yield | 5.4% |
| | | | | | | 7093.1 | 7491.3 | 9431.4 | 9634.0 | 8482.0 | 9827.0 | 9758.0 | 11690 | 12137 | 13120 | 13830 | 14445 | Revenues ($mill) | 16550 |
| | | | | | | 729.8 | 714.2 | 596.4 | 695.8 | 682.1 | 639.0 | 560.0 | 719.0 | 749.0 | 936.0 | 845 | 880 | Net Profit ($mill) | 945 |
| | | | | | | 35.8% | 34.3% | 34.8% | 40.0% | 36.9% | 33.7% | 34.3% | 33.6% | 35.2% | 32.6% | 33.0% | 33.0% | Income Tax Rate | 33.0% |
| | | | | | | 5% | 8% | 1.2% | 1.3% | 2.2% | 4.2% | 7.7% | 2.2% | 1.6% | 1.9% | 2.0% | 2.0% | AFUDC % to Net Profit | 2.0% |
| | | | | | | 39.2% | 44.4% | 48.6% | 48.2% | 50.1% | 50.4% | 47.4% | 49.6% | 50.2% | 45.6% | 50.0% | 50.5% | Long-Term Debt Ratio | 50.0% |
| | | | | | | 58.4% | 53.1% | 49.1% | 49.6% | 48.1% | 48.0% | 51.0% | 49.0% | 48.5% | 53.1% | 49.0% | 49.0% | Common Equity Ratio | 49.5% |
| | | | | | | 10325 | 10186 | 11137 | 11417 | 12302 | 13369 | 13828 | 14921 | 16515 | 16687 | 19195 | 19710 | Total Capital ($mill) | 21730 |
| | | | | | | 11407 | 11354 | 11893 | 12248 | 13329 | 15225 | 16106 | 17112 | 18445 | 19914 | 21070 | 22925 | Net Plant ($mill) | 26490 |
| | | | | | | 8.6% | 8.6% | 7.0% | 7.8% | 7.1% | 6.3% | 5.6% | 6.3% | 6.0% | 7.0% | 6.0% | 6.0% | Return on Total Cap'l | 5.5% |
| | | | | | | 11.6% | 12.6% | 10.4% | 11.8% | 11.1% | 9.6% | 7.7% | 9.6% | 9.1% | 10.3% | 9.0% | 9.0% | Return on Shr. Equity | 8.5% |
| | | | | | | 11.8% | 12.9% | 10.7% | 12.0% | 11.3% | 9.8% | 7.8% | 9.7% | 9.2% | 10.4% | 9.0% | 9.0% | Return on Com Equity D | 8.5% |
| | | | | | | 3.6% | 4.1% | 2.2% | 3.8% | 4.0% | 2.9% | .8% | 2.6% | 2.6% | 3.9% | 2.0% | 2.5% | Retained to Com Eq | 2.5% |
| | | | | | | 70% | 69% | 80% | 69% | 65% | 71% | 89% | 74% | 73% | 63% | 77% | 75% | All Div'ds to Net Prof | 74% |

**CAPITAL STRUCTURE as of 6/30/08**
Total Debt $9461 mill. Due in 5 Yrs $2128 mill.
LT Debt $8802 mill. LT Interest $480.0 mill.
(LT interest earned: 4.5x)
**Pension Assets-12/07 $8.4 bill. Oblig. $8.7 bill.**

**Pfd Stock $212.6 mill. Pfd Div'd $12.5 mill.**
1,915,319 shs. $5 cum. no par, call $105 a sh.
375,626 shs. 4.65% cum. $100 par, call $101 to $102.50 a sh. Sinking Fund ends 2009

**Common Stock 273,190,866 shs.**
**MARKET CAP: $11.2 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -1.8 | -1.9 | -1.6 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | 565 | 565 | 565 |
| Peak Load, Summer (Mw) | 13059 | 13141 | 12807 |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (yr-end) | +.8 | +.9 | +.9 |
| Fixed Charge Cov. (%) | 312 | 291 | 339 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 5.0% | 2.0% | 3.5% |
| "Cash Flow" | 1.0% | -.5% | 5.0% |
| Earnings | .5% | .5% | 1.0% |
| Dividends | 1.0% | 1.0% | 1.0% |
| Book Value | 2.5% | 3.0% | 3.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 2801 | 2406 | 3375 | 3108 | 11690 |
| 2006 | 3317 | 2555 | 3441 | 2824 | 12137 |
| 2007 | 3357 | 2956 | 3579 | 3228 | 13120 |
| 2008 | 3577 | 3149 | 3750 | 3354 | 13830 |
| 2009 | 3725 | 3320 | 3900 | 3500 | 14445 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .75 | .48 | 1.17 | .59 | 2.99 |
| 2006 | .74 | .51 | .92 | .78 | 2.95 |
| 2007 | .99 | .58 | 1.15 | .76 | 3.48 |
| 2008 | .87 | .42 | 1.10 | .66 | 3.05 |
| 2009 | .85 | .45 | 1.15 | .70 | 3.15 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .565 | .565 | .565 | .565 | 2.26 |
| 2005 | .57 | .57 | .57 | .57 | 2.28 |
| 2006 | .575 | .575 | .575 | .575 | 2.30 |
| 2007 | .58 | .58 | .58 | .58 | 2.32 |
| 2008 | .585 | .585 | | | |

**BUSINESS:** Consolidated Edison, Inc., parent of Consolidated Edison Company of New York, Inc., sells electricity (75% of revs.), gas (19%), steam (6%) in most of New York City and Westchester County. Acquired Orange & Rockland Utilities 7/99. Commercial rev. ratio (52%) compares with 32% for the industry. Nonincome taxes and avg. price per kwh are among the highest in U.S. Fuel costs: 67% of revenues; labor costs: 14%. 2007 reported deprec. rate: 2.9%. In '07, purchased almost all energy it sold on firm contracts with nonutility generators. Has 15,214 employees. Chairman, Chief Executive Officer & President: Kevin Burke. Incorporated: N.Y. Add.: 4 Irving Place, New York, N.Y. 10003. Tel.: 212-460-3903. Internet: www.coned.com.

**Consolidated Edison will spend $5.5 billion on capital improvements over the next three years.** Though the economy remains soft, energy consumption in ED's service area continues to rise, albeit at a lesser rate than before. Increased demand requires the installation of several thousand miles of distribution cable and construction of new substations. Moreover, most of these wires must be strung underground, and that is five to 10 times more expensive than building overhead lines. Too, costs keep escalating for materials used in making these additions. In the past 18 months, copper and steel prices have jumped more than 20% and 70%, respectively. Con ED has also invested in new, sophisticated computer systems to keep better track of customer outages. To pay for these expenditures . . .

**The company has filed for higher rates.** The request follows closely on the heels of last March's order granting a disappointing hike for one year only. This led two major rating agencies to lower ED's bond ratings a notch and a third to put the utility on negative watch. The company also faces a $200 million increase in property taxes due to the rising value of its transmission system. To achieve reimbursement for these outlays, management offered regulators two proposals, one for an increase of $654 million, the other for $557 million. Both are for a three-year period. The first is more heavily loaded up front. The petition puts regulators in a difficult position as arbiters between utility investors and customers. We expect them to award an amount below the request.

**Earnings may decline in 2008.** Negatives include loss of income from the divestiture of profitable merchant plants, a first-quarter charge for last year's power outage, higher interest expense, and more shares outstanding. Despite last April's rate hike of $425 million, we estimate 2008 earnings will decline 12%, to $3.05 a share. Next year's results will depend on the decision in the pending rate case.

**The stock offers more positives than negatives.** The yield is above average, and ED's near-highest Financial Strength rating of A+ remains one of the industry's best. But investors seeking dividend growth will likely fare better elsewhere.

*Arthur H. Medalie* *August 29, 2008*

(A) EPS diluted. Excl. nonrecur. losses: '02, 11¢; '03, 45¢. Next egs. report due late Oct.
(B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvest. plan avail. (C) Includes intangibles. In '07: $18.17/sh. (D) Rate base: net original cost. Rate all'd on elec. common equity in '08: 9.1%; earned on '07 average common equity, 10.8%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 25 |
| Earnings Predictability | 85 |

# CONSTELLATION EGY. NYSE-CEG

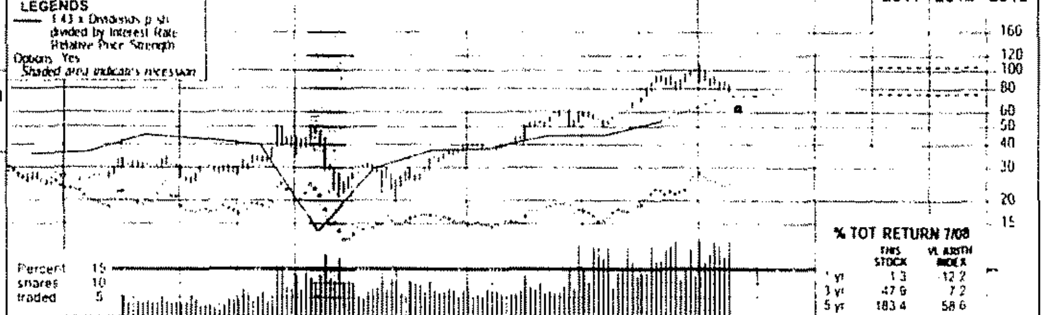
RECENT PRICE **62.62** | P/E RATIO **12.8** (Trailing: 14.3 Median: 15.0) | RELATIVE P/E RATIO **0.83** | DIV'D YLD **3.3%** | **VALUE LINE**

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 34.3 | 35.3 | 31.5 | 52.1 | 50.1 | 32.4 | 39.6 | 44.9 | 62.6 | 70.2 | 104.3 | 108.0 |
| Low | 24.8 | 29.3 | 24.7 | 27.1 | 20.9 | 19.3 | 25.2 | 35.9 | 43.0 | 50.6 | 68.8 | 57.1 |

Target Price Range 2011 2012 2013

TIMELINESS 3 Raised 8/1/08
SAFETY 2 Lowered 3/20/92
TECHNICAL 4 Lowered 8/29/08
BETA .85 (1.00 = Market)

LEGENDS
— 1.43 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession



**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 105 | (+70%) | 16% |
| Low | 75 | (+20%) | 8% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Options | 0 | 3 | 3 | 0 | 4 | 0 | 0 | 2 | 1 |
| to Sell | 0 | 6 | 3 | 0 | 8 | 0 | 0 | 3 | 2 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 169 | 223 | 207 |
| to Sell | 208 | 201 | 242 |
| Hld's(000) | 131440 | 126372 | 120891 |

Percent shares traded 15 10 5

**% TOT. RETURN 7/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 1.3 | -12.2 |
| 3 yr. | 47.9 | 7.2 |
| 5 yr. | 183.4 | 58.6 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17.33 | 18.27 | 18.86 | 19.89 | 21.35 | 22.40 | 22.50 | 25.32 | 25.77 | 24.00 | 28.53 | 57.82 | 71.17 | 96.08 | 106.83 | 118.77 | 112.60 | 122.15 | Revenues per sh | 153.50 |
| 3.10 | 3.45 | 3.93 | 4.59 | 4.45 | 4.66 | 4.93 | 5.57 | 5.78 | 5.02 | 5.50 | 6.31 | 6.89 | 6.78 | 6.81 | 7.52 | 7.65 | 9.45 | "Cash Flow" per sh | 11.00 |
| 1.63 | 1.85 | 1.93 | 2.02 | 1.85 | 1.97 | 2.06 | 2.18 | 2.30 | 2.20 | 2.29 | 2.76 | 3.19 | 3.38 | 3.76 | 4.29 | 4.30 | 5.90 | Earnings per sh A | 6.75 |
| 1.43 | 1.47 | 1.51 | 1.55 | 1.59 | 1.63 | 1.67 | 1.68 | 1.68 | .48 | .96 | 1.04 | 1.14 | 1.34 | 1.51 | 1.74 | 1.91 | 2.10 | Div'd Decl'd per sh B■ | 2.70 |
| 2.71 | 3.27 | 3.27 | 2.48 | 2.44 | 2.53 | 2.27 | 2.92 | 7.17 | 8.05 | 5.05 | 3.92 | 3.99 | 4.26 | 5.33 | 7.26 | 11.90 | 10.45 | Cap'l Spending per sh | 8.25 |
| 17.63 | 17.94 | 18.42 | 19.07 | 19.35 | 19.44 | 19.98 | 20.01 | 20.95 | 23.46 | 23.43 | 24.67 | 26.81 | 27.57 | 25.53 | 29.93 | 32.35 | 36.20 | Book Value per sh C | 48.50 |
| 143.78 | 146.03 | 147.53 | 147.53 | 147.67 | 147.67 | 149.25 | 149.56 | 150.53 | 163.71 | 164.84 | 167.82 | 176.33 | 175.30 | 180.52 | 178.44 | 178.50 | 174.00 | Common Shs Outst'g D | 180.00 |
| 13.6 | 13.8 | 11.8 | 12.4 | 14.7 | 14.0 | 15.1 | 13.2 | 15.8 | 16.4 | 12.1 | 11.6 | 12.5 | 15.0 | 15.6 | 20.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | 13.5 |
| .82 | .82 | .77 | .83 | .92 | .81 | .80 | .75 | 1.03 | .84 | .66 | .67 | .66 | .85 | .84 | 1.09 | *Value Line* | | Relative P/E Ratio | .90 |
| 6.5% | 5.8% | 6.6% | 6.2% | 5.9% | 5.9% | 5.3% | 5.8% | 4.6% | 1.3% | 3.5% | 3.2% | 2.9% | 2.5% | 2.6% | 2.0% | *estimates* | | Avg Ann'l Div'd Yield | 3.0% |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $4919.5 mill. **Due in 5 Yrs** $1853.2 mill.
**LT Debt** $4686.7 mill. **LT Interest** $300.0 mill.
(LT interest earned: 5.3x)
**Leases, Uncapitalized** Annual rentals $505.6 mill.

**Pension Assets-12/07** $1.26 bill. **Oblig.** $1.64 bill.
**Pfd Stock** $190.0 mill. **Pfd Div'd** $13.2 mill.
Incl. 1,900,000 shs. 6.70%-7.125% preference, callable at $102.68-$103.50; all $100 par; not subject to mandatory redemption.
**Common Stock** 178,381,136 shs.
**as of 4/30/08**
**MARKET CAP: $11 billion (Large Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3358.1 | 3786.2 | 3878.5 | 3926.3 | 4703.0 | 9703.0 | 12550 | 17132 | 19285 | 21193 | 20100 | 21800 | Revenues ($mill) | 28250 |
| 327.7 | 339.9 | 358.5 | 366.3 | 372.1 | 472.2 | 567.8 | 619.9 | 696.6 | 796.4 | 790 | 1075 | Net Profit ($mill) | 1260 |
| 35.2% | 35.4% | 39.1% | 34.6% | 40.3% | 35.6% | 27.1% | 24.8% | 31.0% | 33.7% | 36.0% | 35.0% | Income Tax Rate | 35.0% |
| 4.1% | 2.9% | -- | 15.7% | 11.8% | 2.9% | 1.9% | 1.6% | 2.0% | 2.4% | 4.0% | 2.0% | AFUDC % to Net Profit | 2.0% |
| 49.7% | 44.7% | 48.6% | 40.2% | 53.2% | 53.8% | 49.5% | 46.1% | 46.8% | 45.7% | 44.0% | 42.5% | Long-Term Debt Ratio | 40.5% |
| 47.3% | 52.0% | 48.5% | 57.0% | 44.6% | 44.2% | 48.6% | 51.9% | 51.1% | 52.4% | 54.0% | 56.0% | Common Equity Ratio | 58.0% |
| 6299.6 | 5758.4 | 6502.3 | 6746.1 | 8666.2 | 9369.7 | 9730.1 | 9474.8 | 9021.6 | 10191 | 10650 | 11550 | Total Capital ($mill) | 15300 |
| 5656.7 | 5523.1 | 6644.0 | 7700.4 | 7957.1 | 9601.5 | 10087 | 10067 | 9222.1 | 9767.1 | 11300 | 12550 | Net Plant ($mill) | 14800 |
| 6.9% | 7.5% | 7.1% | 6.5% | 5.9% | 6.7% | 7.4% | 8.0% | 9.3% | 9.1% | 9.0% | 10.5% | Return on Total Cap'l | 9.5% |
| 10.3% | 10.7% | 10.7% | 9.1% | 9.2% | 10.9% | 11.5% | 12.1% | 14.5% | 14.4% | 13.0% | 16.0% | Return on Shr. Equity | 14.0% |
| 10.3% | 10.9% | 11.0% | 9.2% | 9.3% | 11.1% | 11.7% | 12.3% | 14.8% | 14.7% | 13.5% | 16.5% | Return on Com Equity E | 14.0% |
| 2.0% | 2.5% | 3.0% | 6.0% | 5.7% | 7.0% | 7.7% | 7.7% | 9.1% | 8.9% | 7.5% | 10.5% | Retained to Com Eq | 8.5% |
| 81% | 78% | 74% | 37% | 41% | 39% | 36% | 39% | 40% | 40% | 45% | 36% | All Div'ds to Net Prof | 40% |

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.0 | -3.8 | +3.3 |
| Avg. Indust. Use (MWH) | 762 | 677 | 647 |
| Avg. Indust. Revs. per KWH (¢) | 8.60 | 10.02 | 11.01 |
| Capacity at Peak (Mw) | 6410 | NA | NA |
| Peak Load, Summer (Mw) | 4000 | NA | NA |
| Nuclear Capacity Factor (%) | 94 | NA | NA |
| % Change Customers (yr-end) | +1.1 | +.8 | +.9 |
| Fixed Charge Cov. (%) | 317 | 354 | 395 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 17.5% | 32.5% | 6.0% |
| "Cash Flow" | 4.5% | 5.5% | 7.5% |
| Earnings | 7.0% | 11.0% | 10.0% |
| Dividends | -.5% | 8.0% | 10.0% |
| Book Value | 3.5% | 4.0% | 10.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 3572 | 3479 | 4922 | 5159 | 17132 |
| 2006 | 4859 | 4379 | 5393 | 4654 | 19285 |
| 2007 | 5111 | 4876 | 5857 | 5349 | 21193 |
| 2008 | 4827 | 5077 | 5400 | 4811 | 20100 |
| 2009 | 5200 | 5200 | 6200 | 5200 | 21800 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .66 | .66 | 1.02 | 1.04 | 3.38 |
| 2006 | .56 | .41 | 1.69 | 1.10 | 3.76 |
| 2007 | 1.08 | .59 | 1.24 | 1.38 | 4.29 |
| 2008 | .81 | .95 | .85 | 1.69 | 4.30 |
| 2009 | 1.40 | 1.40 | 1.40 | 1.70 | 5.90 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .26 | .285 | .285 | .285 | 1.12 |
| 2005 | .285 | .335 | .335 | .335 | 1.29 |
| 2006 | .335 | .378 | .378 | .378 | 1.47 |
| 2007 | .378 | .435 | .435 | .435 | 1.68 |
| 2008 | .435 | .478 | .478 | | |

**BUSINESS:** Constellation Energy Group, Inc. is a holding company for Baltimore Gas and Electric Company, which distributes electricity and gas in Baltimore and parts of central Maryland. Customers: 1.2 million electric, 646,000 gas. Has nonregulated businesses: Constellation Energy Commodities Group and Constellation NewEnergy. Owns 30% of Constellation Energy Partners. Electric revenue breakdown, '07: residential, 64%; commercial, 34%; industrial, 2%. Generating sources, '07: nuclear, 61%; coal, 35%; other, 4%. Fuel costs: 78% of revenues. '07 deprec. rate: 3.8%. Has 10,200 employees. Chairman, President & CEO: Mayo A. Shattuck III. Inc.: MD. Address: 750 East Pratt St., Baltimore, MD 21202. Tel.: 410-783-2800. Internet: www.constellation.com.

**Constellation Energy stock is off sharply of late.** In August, the share price fell precipitously after a rating agency cut the company's credit rating from BBB+ to BBB. Another agency soon followed suit. Maintaining an investment-grade rating is very important for a company that is as heavily involved in energy trading and marketing as is Constellation (which gets most of its profits from the nonregulated side of its business), because a company must provide more collateral as its credit rating declines. The latest rating is still two notches above a noninvestment-grade level, but if it falls below investment grade, Constellation would have to provide over $3 billion in additional collateral.

**Even before the recent decline, the stock was performing poorly.** In early 2008, the share price was more than $100. In late July, perhaps to address investors' concerns as Constellation reported June-quarter earnings, management stated that it is "considering various strategic alternatives for our commodities business." This might well result in a joint venture similar to the one that Sempra Energy (reviewed in Issue 11) entered into with Royal Bank of Scotland, although finding the right partner won't be easy.

**We have reduced our earnings estimates for the second half of 2008 and all of 2009.** Based on Constellation's guidance, it appears we overestimated the company's earning power over the remainder of 2008 by $0.50-$1.00 a share. Moreover, we have lowered our 2009 forecast by $0.65 a share, to $5.90. This would still be a record tally for Constellation, and by a wide margin. But this company has a lot of moving parts on the nonutility side of its operations, which makes its earnings much more unpredictable than its high Earnings Predictability Index suggests.

**Investors with a long time horizon, who can swallow the inherent uncertainties of the energy-marketing business, should take advantage of the recent weakness in the share price as a buying opportunity.** Even after we reduced our earnings expectations, the relative price-earnings ratio is lower than it has been for the past few years. Projected total returns to 2011-2013 are well above the industry average.

*Paul E. Debbas, CFA* *August 29, 2008*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '02, 91¢; '03, ($1.09); '04, (8¢); '05, (4¢); '06, 36¢; '07, 22¢; gains (loss) from disc. ops.: '05, 13¢; '06, $1.04; '07, (1¢). Next earnings report due late Oct. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. (C) Incl. def'd charges. In '07: $4.69/sh. (D) In mill. (E) Rate base: Fair value. Rate all'd on com. eq. in '93 (elec.): none specified; in '05 (gas): 11%; earned on avg. com. eq., '07: 15.5%. Regulatory Climate: Avg.

| | |
|---|---|
| **Company's Financial Strength** | A |
| **Stock's Price Stability** | 90 |
| **Price Growth Persistence** | 85 |
| **Earnings Predictability** | 80 |

# DOMINION RES. NYSE-D

RECENT PRICE 42.76 | P/E RATIO 13.8 (Trailing 17.6 / Median 18.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 3 Raised 9/1/06
SAFETY 2 Raised 9/11/98
TECHNICAL 3 Lowered 5/23/08
BETA .75 (1.00 = Market)

**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+50%) | 14% |
| Low | 45 | (+5%) | 6% |

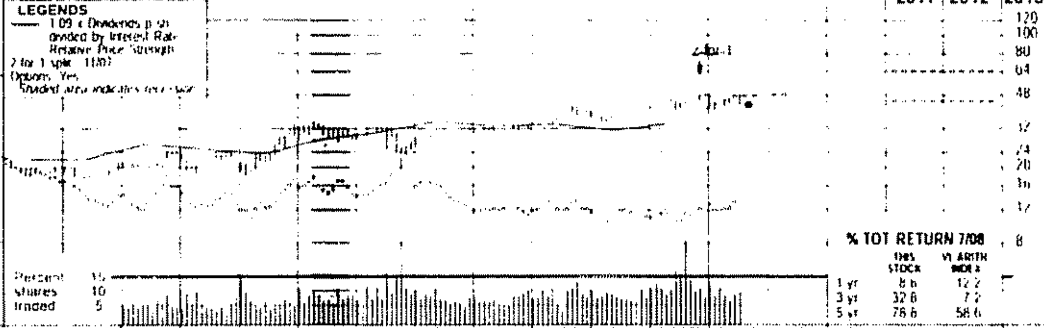
**Insider Decisions**

| | D | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| Options | 3 | 5 | 6 | 0 | 5 | 0 | 0 | 6 | 0 |
| to Sell | 3 | 5 | 5 | 0 | 7 | 0 | 0 | 6 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 190 | 286 | 257 |
| to Sell | 418 | 299 | 336 |
| Hld's(000) | 334081 | 334721 | 340177 |

| High | 21.4 | 24.5 | 24.7 | 34.0 | 35.0 | 33.5 | 33.0 | 34.4 | 43.5 | 42.2 | 49.4 | 48.5 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Low | 16.6 | 18.9 | 18.3 | 17.4 | 27.6 | 17.7 | 25.9 | 30.4 | 33.3 | 34.4 | 39.8 | 38.6 |




**% TOT. RETURN 7/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 8.6 | 12.2 |
| 3 yr. | 32.6 | 7.2 |
| 5 yr. | 76.6 | 58.6 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11.57 | 12.19 | 13.02 | 13.18 | 13.36 | 20.44 | 15.65 | 14.61 | 18.84 | 19.94 | 16.58 | 18.58 | 20.55 | 26.00 | 23.61 | 27.16 | 26.60 | 26.90 | Revenues per sh | 29.50 |
| 3.02 | 3.30 | 3.16 | 3.00 | 3.22 | 3.89 | 2.99 | 3.68 | 3.71 | 3.92 | 4.45 | 3.97 | 4.16 | 3.71 | 4.91 | 5.08 | 4.80 | 5.05 | "Cash Flow" per sh | 6.00 |
| 1.33 | 1.56 | 1.41 | 1.23 | 1.33 | 1.50 | .86 | 1.50 | 1.25 | 1.49 | 2.41 | 1.96 | 2.12 | 1.50 | 2.40 | 2.13 | 3.05 | 3.30 | Earnings per sh A | 4.00 |
| 1.20 | 1.24 | 1.25 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.29 | 1.30 | 1.34 | 1.38 | 1.46 | 1.63 | 1.80 | Div'd Decl'd per sh B ■ † | 2.20 |
| 2.19 | 2.12 | 1.92 | 1.64 | 1.34 | 1.73 | 1.60 | 2.16 | 2.82 | 2.31 | 2.17 | 5.20 | 3.88 | 4.84 | 5.81 | 6.88 | 6.35 | 6.80 | Cap'l Spending per sh | 6.75 |
| 12.61 | 13.19 | 13.30 | 13.44 | 13.59 | 13.42 | 13.67 | 12.75 | 14.22 | 15.81 | 16.57 | 16.21 | 16.80 | 14.98 | 18.50 | 16.30 | 18.40 | 20.85 | Book Value per sh C | 27.25 |
| 327.69 | 336.25 | 344.81 | 352.83 | 362.44 | 375.60 | 388.92 | 372.64 | 491.60 | 529.40 | 616.20 | 650.00 | 680.00 | 694.00 | 698.00 | 577.00 | 581.00 | 597.00 | Common Shs Outst'g D | 622.00 |
| 14.3 | 14.3 | 13.8 | 15.4 | 14.8 | 12.5 | 24.6 | 14.5 | 19.4 | 20.9 | 12.0 | 15.2 | 15.1 | 24.9 | 16.0 | 20.6 | Bold figures are | Value Line | Avg Ann'l P/E Ratio | 14.0 |
| .87 | .84 | .91 | 1.03 | .93 | .72 | 1.28 | .83 | 1.26 | 1.07 | .66 | .67 | .80 | 1.33 | .86 | 1.09 | estimates | | Relative P/E Ratio | .95 |
| 6.3% | 5.6% | 6.6% | 6.9% | 6.6% | 6.9% | 6.1% | 5.9% | 5.3% | 4.1% | 4.4% | 4.3% | 4.0% | 3.6% | 3.6% | 3.3% | | | Avg Ann'l Div'd Yield | 4.0% |

**CAPITAL STRUCTURE as of 6/30/08**
Total Debt $17397 mill. Due in 5 Yrs $6443 mill.
LT Debt $14204 mill. LT Interest $945.0 mill.
(LT interest earned: 3.4x)
**Leases, Uncapitalized** Annual rentals $81.0 mill.
**Pension Assets**-12/07 $5.10 bill. **Oblig.** $3.69 bill.

**Pfd Stock** $257.0 mill. **Pfd Div'd** $16.0 mill.
1,340,140 shs. $4.04-$7.05, $100 liq. pref., redeemable at $101.00-$112.50/sh.; 2,500,000 var. rate Money Market Pfd. shs. Excl. pfd. due within 1 year.
**Common Stock** 579,937,884 shs.

**MARKET CAP: $25 billion (Large Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 6086.2 | 5520.0 | 9260.0 | 10558 | 10218 | 12078 | 13972 | 18041 | 16482 | 15674 | 15450 | 16050 | Revenues ($mill) | 18300 |
| 400.0 | 639.0 | 624.0 | 775.0 | 1376.0 | 1261.0 | 1425.0 | 1050.0 | 1704.0 | 1414.0 | 1785 | 1965 | Net Profit ($mill) | 2525 |
| 29.0% | 29.4% | 31.7% | 38.4% | 33.1% | 34.9% | 35.4% | 35.7% | 35.5% | 33.4% | 39.0% | 38.0% | Income Tax Rate | 38.0% |
| 3% | 4.7% | 3.5% | 5.3% | 6.9% | 7.9% | 4.9% | 9.7% | 7.9% | 7.3% | 8.0% | 6.0% | AFUDC % to Net Profit | 5.0% |
| 44.2% | 55.1% | 58.3% | 60.2% | 56.2% | 59.4% | 57.0% | 57.9% | 52.9% | 57.8% | 55.0% | 52.5% | Long-Term Debt Ratio | 48.5% |
| 46.4% | 37.8% | 38.9% | 38.0% | 42.7% | 39.7% | 42.0% | 41.1% | 46.2% | 41.1% | 44.0% | 47.0% | Common Equity Ratio | 50.5% |
| 11461 | 12582 | 17987 | 22003 | 23927 | 26571 | 27190 | 25307 | 27961 | 22898 | 24400 | 26550 | Total Capital ($mill) | 33400 |
| 10637 | 10764 | 14849 | 18681 | 20257 | 25850 | 26716 | 28940 | 29382 | 21352 | 24025 | 27000 | Net Plant ($mill) | 35700 |
| 5.7% | 6.8% | 5.9% | 5.3% | 7.7% | 6.5% | 6.9% | 6.1% | 7.9% | 8.5% | 9.0% | 9.0% | Return on Total Cap'l | 9.0% |
| 6.3% | 11.3% | 8.3% | 8.9% | 13.2% | 11.7% | 12.2% | 9.9% | 12.9% | 14.6% | 16.5% | 15.5% | Return on Shr. Equity | 14.5% |
| 6.3% | 12.0% | 8.0% | 9.0% | 13.3% | 11.8% | 12.3% | 9.9% | 13.1% | 14.9% | 16.5% | 15.5% | Return on Com Equity E | 15.0% |
| NMF | 1.7% | NMF | 1.2% | 6.3% | 4.0% | 4.8% | 1.1% | 5.6% | 5.0% | 7.5% | 7.0% | Retained to Com Eq | 7.0% |
| NMF | 88% | 109% | 87% | 54% | 67% | 62% | 89% | 58% | 67% | 54% | 55% | All Div'ds to Net Prof | 55% |

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.2 | -1.8 | +4.9 |
| Avg. Indust. Use (MWH) | 15704 | 16014 | 16221 |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 18897 | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.9 | +1.7 | +.6 |
| Fixed Charge Cov. (%) | 220 | 293 | 246 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 5.0% | 7.0% | 2.5% |
| "Cash Flow" | 3.0% | 2.5% | 4.5% |
| Earnings | 4.0% | 3.0% | 12.0% |
| Dividends | 1.0% | 1.5% | 8.0% |
| Book Value | 2.0% | 1.5% | 8.5% |

| Calendar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 4736 | 3646 | 4564 | 5095 | 18041 |
| 2006 | 4951 | 3548 | 4016 | 3967 | 16482 |
| 2007 | 4661 | 3730 | 3589 | 3694 | 15674 |
| 2008 | 4389 | 3452 | 3700 | 3909 | 15450 |
| 2009 | 4550 | 3600 | 3850 | 4050 | 16050 |

| Calendar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .63 | .49 | .02 | .38 | 1.50 |
| 2006 | .78 | .35 | .94 | .32 | 2.40 |
| 2007 | .69 | .45 | .44 | .51 | 2.13 |
| 2008 | 1.01 | .47 | .87 | .70 | 3.05 |
| 2009 | 1.05 | .55 | .95 | .75 | 3.30 |

| Calendar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .323 | .323 | .323 | .333 | 1.30 |
| 2005 | .335 | .335 | .335 | .335 | 1.34 |
| 2006 | .345 | .345 | .345 | .345 | 1.38 |
| 2007 | .355 | .355 | .355 | .395 | 1.46 |
| 2008 | .395 | .395 | | | |

**BUSINESS:** Dominion Resources Inc. (DRI) is a holding company for Virginia Power, which serves 2.4 million customers in Virginia and northeastern North Carolina. Acquired Consolidated Natural Gas (1.7 million customers in Ohio, Pennsylvania & West Virginia) 1/00. Nonutility operations include independent power production and gas & oil production. Electric revenue breakdown: '07: residential 44%; commercial 30%; industrial 8%; other 18%. Generating sources '07: coal 35%; nuclear 29%; gas 6%; oil 2%; purchased 28%. Fuel costs: 44% of revs. '07 deprec. rate: 4.6%. Has 17,000 employees. Chairman: Thos. E. Capps. President & CEO: Thomas F. Farrell II. Inc.: VA. Address: P.O. Box 26532, Richmond, VA 23261-6532. Tel.: 804-819-2000. Internet: www.dom.com.

**Dominion Resources' earnings are likely to wind up much higher this year.** The company did not fully recover its fuel costs until mid-2007; unrecovered fuel costs hurt net profit by $213 million in the first half of 2007. In addition, average shares outstanding are down sharply, and interest expense is lower. Dominion sold most of its oil and gas exploration and production assets in 2007 and used the proceeds to buy back stock and retire debt.

**We expect profits to rise again in 2009.** We assume higher prices from Dominion's fleet of nonregulated generating assets, an earnings benefit from one fewer refueling outage at the Millstone nuclear station, and rate relief at the company's gas utility in Ohio, which is seeking a $73 million rate increase.

**The company has some key projects in various stages of development.** Virginia Power has begun construction of a 585-megawatt coal-fired plant at an estimated cost of $1.8 billion. The new facility should begin commercial operation in 2012. In addition, Dominion is expanding its liquefied natural gas terminal; building a 582-mw gas-fired plant; and constructing two transmission lines. Finally, the company has already begun the licensing process with the intent of adding a third unit (1,300-mw) at one of its nuclear stations.

**Dominion has announced two big asset sales.** The company reached another agreement to sell its gas utilities in Pennsylvania and West Virginia after a previous sale fell through. It expects the after-tax proceeds to be around $675 million. The deal should close in 2009. Dominion also sold some natural gas drilling rights, which should net the company $325 million. This transaction should close next month. Dominion will have a royalty interest on these properties. The utility sale will be dilutive to earnings; it's too early to tell about the drilling rights sale. Initially, the proceeds will be used to retire short-term debt; subsequently, this will offset the need for an equity issuance in 2009. We won't adjust our figures until after the deals have closed.

**This stock's yield is about average for a utility.** Rapid dividend growth should produce an above-average (for a utility) 3- to 5-year total return, however.

*Paul E. Debbas, CFA* *August 29, 2008*

(A) Excl. nonrec. gains (losses): '01, (42¢); '03, ($1.46); '04, (22¢); '06, (18¢); '07, $1.67; '08, 21¢; gain (losses) from disc. ops.: '04, (3¢); '05, 1¢; '06, (26¢); '07, (1¢). '05 & '07 EPS don't add due to change in shs. Next egs. due early Nov. (B) Div'ds historically paid in mid-Mar., June, Sept., and Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $8.75/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost, adj. Rate all'd on com. eq. in '92: 11.4%; earned on avg. com. eq. '07: 12.9%. Regul. Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 65 |
| Earnings Predictability | 65 |

# DUKE ENERGY NYSE-DUK

RECENT PRICE 17.69 | P/E RATIO 13.3 (Trailing: 13.2 Median: NMF) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 5.3% | VALUE LINE

TIMELINESS —
SAFETY 2 New 6/1/07
TECHNICAL —
BETA NMF (1.00 = Market)

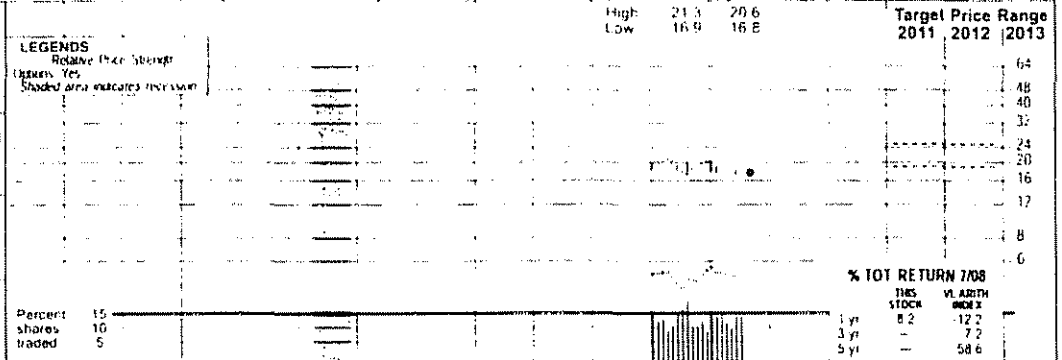
| 2011-13 PROJECTIONS | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+40%) | 13% |
| Low | 19 | (+5%) | 7% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 2 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 2 | 0 | 0 | 4 | 0 | 0 | 2 | 0 |
| to Sell | 0 | 4 | 0 | 0 | 2 | 2 | 0 | 2 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 331 | 364 | 359 |
| to Sell | 308 | 275 | 316 |
| Hld's(000) | 743605 | 759575 | 710165 |




% TOT. RETURN 7/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 8.2 | -12.2 |
| 3 yr. | — | 7.2 |
| 5 yr. | — | 58.6 |

Duke Energy Corporation, in its current configuration began trading on January 3 2007 the day after it spun off its midstream gas operations into a new company Spectra Energy (NYSE SE) to shareholders Duke Energy shareholders received half a share of Spectra Energy for each Duke share held Data for the "old" Duke Energy are not shown because they are not comparable

| 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|
| 8.44 | 10.06 | 11.10 | 11.45 | Revenues per sh | 13.25 |
| 2.62 | 2.70 | 2.75 | 2.85 | "Cash Flow" per sh | 3.25 |
| .92 | 1.20 | 1.30 | 1.35 | Earnings per sh A | 1.50 |
| | .86 | .90 | .94 | Div'd Decl'd per sh B ■ † | 1.06 |
| 2.69 | 2.48 | 4.05 | 3.70 | Cap'l Spending per sh | 2.50 |
| 20.77 | 16.80 | 17.20 | 17.65 | Book Value per sh C | 19.00 |
| 1257.0 | 1262.0 | 1262.00 | 1267.00 | Common Shs Outst'g D | 1285.00 |
| | 16.7 | Bold figures are | | Avg Ann'l P/E Ratio | 14.5 |
| | .86 | Value Line | | Relative P/E Ratio | .95 |
| | 4.4% | estimates | | Avg Ann'l Div'd Yield | 4.8% |
| 10607 | 12720 | 14000 | 14500 | Revenues ($mill) | 16950 |
| 1080.0 | 1522.0 | 1645 | 1720 | Net Profit ($mill) | 1950 |
| 29.4% | 31.9% | 33.0% | 33.0% | Income Tax Rate | 33.0% |
| 6.9% | 7.2% | 13.0% | 15.0% | AFUDC % to Net Profit | 9.0% |
| 41.0% | 30.9% | 35.5% | 38.5% | Long-Term Debt Ratio | 44.5% |
| 59.0% | 69.1% | 64.5% | 61.5% | Common Equity Ratio | 55.5% |
| 44220 | 30697 | 33600 | 36450 | Total Capital ($mill) | 43800 |
| 41447 | 31110 | 34400 | 37225 | Net Plant ($mill) | 43800 |
| 3.1% | 6.0% | 6.0% | 6.0% | Return on Total Cap'l | 6.0% |
| 4.1% | 7.2% | 7.5% | 7.5% | Return on Shr. Equity | 8.0% |
| 4.1% | 7.2% | 7.5% | 7.5% | Return on Com Equity E | 8.0% |
| 4.1% | 2.0% | 2.5% | 2.5% | Retained to Com Eq | 2.5% |
| 57% | 72% | 69% | 69% | All Div'ds to Net Prof | 70% |

**CAPITAL STRUCTURE as of 3/31/08**
Total Debt $12102 mill. Due in 5 Yrs $5799.0 mill.
LT Debt $10083 mill. LT Interest $625.0 mill.
incl. $108.0 mill. capitalized leases
(LT interest earned: 4.3x)
Leases, Uncapitalized Annual rentals $121.0 mill.

Pension Assets-12/07 $4.32 bill. Oblig. $4.30 bill.

Pfd Stock None

Common Stock 1,264,614,744 shs.
as of 5/2/08

MARKET CAP: $22 billion (Large Cap)

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +2.3 | +50.3 | +17.8 |
| Avg. Indust. Use (MWH) | 3642 | 2956 | 2635 |
| Avg. Indust. Revs. per KWH (¢) | 4.31 | 5.00 | 4.32 |
| Capacity at Peak (Mw) F | 18828 | 18990 | 19645 |
| Peak Load, Summer (Mw) F | 17294 | 16623 | 17476 |
| Annual Load Factor (%) F | 56.0 | 58.0 | 57.0 |
| % Change Customers (avg.) | +2.0 | +72.7 | +1.4 |
| Fixed Charge Cov. (%) | NMF | 211 | 345 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd 2007 to '11-'13 |
|---|---|---|---|
| Revenues | -- | -- | 5.5% |
| "Cash Flow" | -- | -- | 4.0% |
| Earnings | -- | -- | 4.5% |
| Dividends | -- | -- | 4.5% |
| Book Value | -- | -- | 2.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | -- | -- | -- | -- | -- |
| 2006 | -- | -- | -- | -- | 10607 |
| 2007 | 3035 | 2966 | 3688 | 3031 | 12720 |
| 2008 | 3337 | 3229 | 4084 | 3350 | 14000 |
| 2009 | 3500 | 3300 | 4200 | 3500 | 14500 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | -- | -- | -- | -- | -- |
| 2006 | -- | | | | .92 |
| 2007 | .26 | .24 | .45 | .25 | 1.20 |
| 2008 | .37 | .27 | .43 | .23 | 1.30 |
| 2009 | .40 | .25 | .45 | .25 | 1.35 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | -- | -- | | | -- |
| 2005 | -- | -- | -- | -- | -- |
| 2006 | | | -- | | -- |
| 2007 | .21 | .21 | .22 | .22 | .86 |
| 2008 | .22 | .22 | .23 | | |

BUSINESS: Duke Energy Corporation is a holding company for utilities with 3.9 million electric customers in North Carolina, South Carolina, Ohio, Indiana, and Kentucky, and 500,000 gas customers in Ohio, Indiana, and Kentucky. Owns independent power plants & has a joint venture in real estate. Acquired Cinergy 4/06; spun off midstream gas operations 1/07. Electric rev. breakdown, '07: residential, 41%; commercial, 31%; industrial, 20%; other, 8%. Generating sources, '07: coal, 63%; nuclear, 30%; purchased & other, 7%. Fuel, gas & petroleum costs: 47% of revenues. Has 23,900 employees. Chairman, President & CEO: James E. Rogers. Inc.: North Carolina. Address: 526 South Church St., Charlotte, NC 28202-1802. Tel.: 704-594-6200. Internet: www.duke-energy.com.

**Duke Energy has filed an electric regulatory plan in Ohio,** as required under a new law pertaining to electric generation in the state. The plan requests a price increase of 6.2% in 2009, followed by smaller changes in 2010 and 2011. The increase in 2009 (along with a reduction in amortization) will boost pretax earnings by $150 million next year. An order from the Public Utilities Commission of Ohio (PUCO) is due by yearend.

**The utility received a gas tariff hike in Ohio, and an electric distribution rate request is pending.** The PUCO approved a settlement calling for a gas rate increase of $18.2 million (3%). Duke is seeking an electric rate boost of $86 million (5.5%). The company did not disclose the return on equity and common-equity ratio in either case. The PUCO's order is expected in the second quarter of 2009.

**Two large generating projects are under construction.** Duke is building an 800-megawatt coal-fired plant in North Carolina at a cost of $2.4 billion and a 630-mw coal gasification plant in Indiana at a cost of $2.35 billion. These are utility investments that will be recovered in rates. Each project is expected to enter commercial operation in 2012.

**Higher earnings are likely in 2008 and 2009.** This year, Duke's nonregulated generating subsidiary is benefiting from more favorable conditions, and its utility operations are benefiting from the end of most of the temporary rate reductions that it agreed to swallow as a condition of its acquisition of Cinergy in 2006. Comparisons in the second half of 2008 will be more difficult, however. Next year, the effects of rate relief in Ohio should outweigh an increase in interest expense that is resulting from Duke's sizable financing needs.

**We continue to like this stock for its hefty yield,** which is roughly one percentage point above the industry average. The balance sheet is in good shape, too. Earnings and dividend growth potential to 2011-2013 are solid and should provide investors with a decent (for a utility) total return over that time. Note that the stock is unranked for Timeliness due to its short trading history since the spinoff of its midstream gas assets into a new company, Spectra Energy, in early 2007.

*Paul E. Debbas, CFA* *August 29, 2008*

(A) Diluted EPS. Excl. loss from disc. ops.: '07, 1¢. Next earnings report due early November. (B) Div'ds historically paid in mid-Mar., June, Sept., & Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intangibles. In '07: $6.20/sh. (D) In mill. (E) Rate base: Net orig. cost. Rates allowed on com. eq. in '08: North Carolina, 11%; in '92: South Carolina, 12.25%; in '93: Ohio, 12.9% (electric); in '04: Indiana, 10.3%. Earned on avg. common equity, '07: 6.4%. Regulatory Climate: Average. (F) Duke Energy Carolinas only.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | NMF |
| Price Growth Persistence | NMF |
| Earnings Predictability | NMF |

# ENTERGY CORP. NYSE-ETR

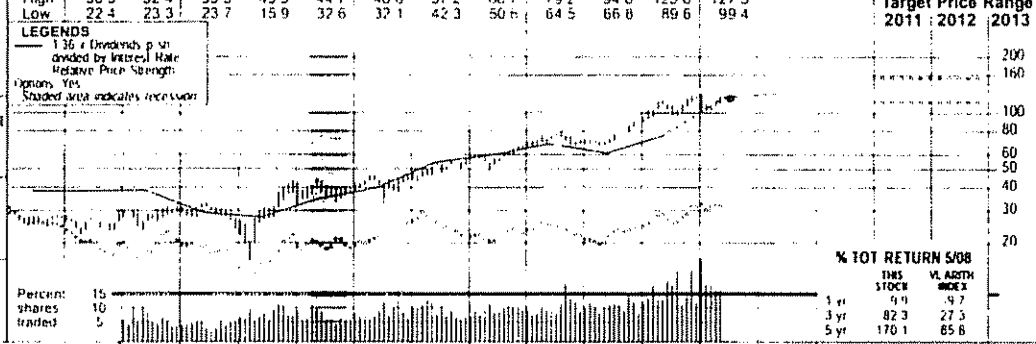
RECENT PRICE 120.03 | P/E RATIO 18.2 (Trailing: 19.6 Median: 14.0) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 2 Raised 6/6/08
SAFETY 2 New 3/31/08
TECHNICAL 3 Lowered 5/9/08
BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 30.3 | 32.4 | 33.5 | 43.9 | 44.7 | 46.8 | 57.2 | 68.7 | 79.2 | 94.0 | 125.0 | 127.5 |
| Low | 22.4 | 23.3 | 23.7 | 15.9 | 32.6 | 32.1 | 42.3 | 50.6 | 64.5 | 66.8 | 89.6 | 99.4 |

Target Price Range 2011 | 2012 | 2013

LEGENDS
1.36 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 155 | (+30%) | 10% |
| Low | 115 | (-5%) | 3% |

Insider Decisions

| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 2 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 3 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |

Institutional Decisions

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 178 | 204 | 217 |
| to Sell | 217 | 215 | 225 |
| Hld's(000) | 157155 | 156125 | 154792 |

Percent shares traded 15 10 5

% TOT. RETURN 5/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr | 9.9 | -9.7 |
| 3 yr | 82.3 | 27.3 |
| 5 yr | 170.1 | 85.6 |

Entergy Corp. (formerly Middle South Utilities) is a registered holding company. On 12/31/93, the company merged with Gulf States Utilities. Entergy shareholders received stock in the new company on a one-for-one basis. Since a cash cap of $250 million was exceeded, GSU shareholders asking for cash were given a 25% cash/75% stock disbursement. The remaining GSU stockholders received .558 share of the new company for each share held.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 46.57 | 35.51 | 45.61 | 43.59 | 37.34 | 40.17 | 45.69 | 46.61 | 53.94 | 59.47 | **64.20** | **65.30** | Revenues per sh | **72.35** |
| 6.11 | 5.06 | 6.49 | 6.41 | 7.62 | 7.43 | 5.33 | 8.18 | 9.83 | 10.86 | **12.45** | **13.25** | "Cash Flow" per sh | **16.05** |
| 2.22 | 2.25 | 2.97 | 3.08 | 3.68 | 3.69 | 3.93 | 4.40 | 5.36 | 5.60 | **6.60** | **7.20** | Earnings per sh A | **9.00** |
| 1.50 | 1.20 | 1.22 | 1.28 | 1.34 | 1.60 | 1.89 | 2.16 | 2.16 | 2.58 | **3.20** | **3.60** | Div'd Decl'd per sh B■ | **4.80** |
| 4.63 | 4.84 | 6.80 | 6.25 | 6.88 | 6.85 | 6.51 | 6.72 | 7.83 | 8.17 | **11.70** | **9.95** | Cap'l Spending per sh | **7.55** |
| 28.79 | 28.81 | 31.89 | 33.78 | 35.24 | 38.02 | 38.26 | 35.71 | 40.45 | 40.71 | **42.20** | **48.00** | Book Value per sh C | **62.25** |
| 246.83 | 247.08 | 219.60 | 220.73 | 222.42 | 228.90 | 216.83 | 216.83 | 202.67 | 193.12 | **187.00** | **193.00** | Common Shs Outst'g E | **199.00** |
| 12.9 | 13.2 | 10.1 | 12.5 | 11.5 | 13.8 | 15.1 | 16.3 | 14.3 | 19.3 | Bold figures are Value Line estimates | | Avg Ann'l P/E Ratio | **15.0** |
| .67 | .75 | .66 | .64 | .63 | .75 | .80 | .87 | .77 | 1.02 | | | Relative P/E Ratio | **1.00** |
| 5.2% | 4.1% | 4.1% | 3.3% | 3.2% | 3.1% | 3.2% | 3.0% | 2.8% | 2.4% | | | Avg Ann'l Div'd Yield | **3.6%** |
| 11495 | 8773.2 | 10016 | 9621.0 | 8305.0 | 9195.0 | 10124 | 10106 | 10932 | 11484 | **12010** | **12600** | Revenues ($mill) | **14400** |
| 570.9 | 595.0 | 710.9 | 716.8 | 878.4 | 874.2 | 933.1 | 943.1 | 1133.0 | 1160.0 | **1325** | **1485** | Net Profit ($mill) | **1905** |
| 37.3% | 37.5% | 40.3% | 38.9% | 25.1% | 35.9% | 28.2% | 37.2% | 28.1% | 30.7% | **31.0%** | **31.0%** | Income Tax Rate | **31.0%** |
| 4.1% | 8.7% | 7.9% | 6.6% | 6.4% | 8.7% | 7.0% | 8.0% | 5.6% | 5.8% | **6.0%** | **6.0%** | AFUDC % to Net Profit | **6.0%** |
| 47.0% | 45.6% | 50.4% | 47.7% | 45.7% | 44.8% | 44.7% | 51.9% | 50.7% | 54.3% | **54.0%** | **52.0%** | Long-Term Debt Ratio | **49.0%** |
| 50.6% | 49.1% | 45.6% | 48.6% | 50.6% | 53.2% | 52.9% | 45.5% | 47.2% | 43.9% | **44.0%** | **46.5%** | Common Equity Ratio | **50.0%** |
| 14042 | 14505 | 15351 | 15353 | 15499 | 16361 | 15696 | 17013 | 17351 | 17902 | **17930** | **19875** | Total Capital ($mill) | **24800** |
| 15329 | 15501 | 16497 | 17264 | 17195 | 18299 | 18696 | 19197 | 19438 | 20974 | **22130** | **22950** | Net Plant ($mill) | **24040** |
| 6.7% | 5.7% | 6.2% | 6.4% | 7.3% | 6.8% | 7.4% | 6.8% | 8.0% | 7.9% | **9.0%** | **8.5%** | Return on Total Cap'l | **9.0%** |
| 7.7% | 7.5% | 9.3% | 8.9% | 10.4% | 9.7% | 10.8% | 11.5% | 13.2% | 14.2% | **16.0%** | **15.5%** | Return on Shr. Equity | **15.0%** |
| 7.4% | 7.7% | 9.7% | 9.3% | 10.9% | 9.8% | 11.0% | 11.9% | 13.5% | 14.4% | **16.5%** | **16.0%** | Return on Com Equity D | **15.0%** |
| 2.1% | 3.7% | 5.8% | 5.7% | 7.1% | 5.6% | 5.8% | 6.0% | 8.0% | 8.0% | **8.5%** | **8.0%** | Retained to Com Eq | **7.0%** |
| 74% | 56% | 43% | 41% | 37% | 44% | 48% | 51% | 42% | 46% | **49%** | **51%** | All Div'ds to Net Prof | **54%** |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $10839 mill. **Due in 5 Yrs** $5623 mill.
**LT Debt** $9928 mill. **LT Interest** $506 mill.
(LT int. earned: 4.4x)
**Pension Assets-12/07** $2764 mill. **Oblig.** $3246 mill.
**Pfd Stock** $311.2 mill. **Pfd Div'd** $24.8 mill.
6,115,105 shs. $4.20 to $7.88, $100 par; 1,000,000 shs. 11.50%, all without sinking fund.

**Common Stock** 191,897,389 shs.
**MARKET CAP: $23.0 billion (Large Cap)**

ELECTRIC OPERATING STATISTICS

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -6.7 | -.4 | +.6 |
| Avg. Indust. Use (MWH) | 957 | 909 | 920 |
| Avg. Indust. Revs. per KWH (¢) | 6.43 | 6.86 | 6.75 |
| Capacity at Peak (Mw) | 22696 | 21727 | 22087 |
| Peak Load, Summer (Mw) | 22000 | 22887 | 22540 |
| Annual Load Factor (%) | 59.0 | 60.0 | 62.0 |
| % Change Customers (yr-end) | -.6 | -9.1 | +2.0 |
| Fixed Charge Cov. (%) | 318 | 281 | 288 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 5.0% | 5.0% | 5.0% |
| "Cash Flow" | 5.5% | 7.0% | 9.0% |
| Earnings | 8.5% | 9.5% | 10.0% |
| Dividends | 2.5% | 12.5% | 13.0% |
| Book Value | 3.5% | 3.0% | 8.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 2022 | 2410 | 3021 | 2653 | 10106 |
| 2006 | 2568 | 2629 | 3255 | 2480 | 10932 |
| 2007 | 2600 | 2769 | 3289 | 2826 | 11484 |
| 2008 | 2865 | **2920** | **3420** | **2805** | **12010** |
| 2009 | **3000** | **3070** | **3570** | **2960** | **12600** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .84 | 1.38 | 1.70 | .48 | 4.40 |
| 2006 | .92 | 1.33 | 1.83 | 1.28 | 5.36 |
| 2007 | 1.03 | 1.32 | 2.29 | .96 | 5.60 |
| 2008 | 1.56 | **1.55** | **2.55** | **.94** | **6.60** |
| 2009 | **1.45** | **1.80** | **2.80** | **1.15** | **7.20** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .45 | .45 | .45 | .54 | 1.89 |
| 2005 | .54 | .54 | .54 | .54 | 2.16 |
| 2006 | .54 | .54 | .54 | .54 | 2.16 |
| 2007 | .54 | .54 | .75 | .75 | 2.58 |
| 2008 | .75 | .75 | | | |

**BUSINESS:** Entergy Corporation has five subsidiaries that supply electricity to portions of Arkansas, Louisiana, Mississippi, Texas, and New Orleans. 2007 revs.: Electric & Gas, 81%; nonutility, 19%. Merged with Gulf States Utilities 12/93. '07 electric revenues: residential, 36%; commercial, 27%; industrial, 28%; other, 9%. Chemical processing, allied products, petroleum refining, paper, and food products industries are main customers. Fuels: gas & oil, 18%; nuclear, 33%; coal, 12%; purchased power, 37%. '07 depreciation rate: 2.7%. Has 14,100 employees. Chairman: Robert Luft. Chief Executive Officer: J. Wayne Leonard. President: Richard Smith. Inc.: DE. Address: 639 Loyola Avenue, New Orleans, Louisiana 70113. Telephone: 504-529-5262. Internet: www.entergy.com.

**Entergy's planned spinoff of its unregulated nuclear plants should be finalized shortly.** The company owns 11 nuclear units, of which six are free of commission oversight. It expects to separate the six units into a new company named Enexus Energy. ETR shareholders would retain their stake in Entergy and would receive all Enexus shares. The deal calls for Enexus to borrow $4.5 billion, from which it would pay Entergy $4 billion. The pact also provides for formation of a company named EquaGen, which would operate nuclear assets of Entergy and Enexus and would be owned equally by both. The spinoff requires various commission approvals. Closing is expected in September.

**Meanwhile, the company is adding fossil-fueled capacity.** Earlier this year, it purchased the Calcasieu peaking unit for $56.4 million. And it has agreed to buy the Ouachita 789-mw gas-fired plant for $210 million, on which it will invest another $436 million in upgrades. Also on the agenda is repowering of the 538-mw Little Gypsy gas-fired plant to burn petroleum coke and other solid fuels. Work here has been delayed pending a study of mercury emissions. The project's cost is estimated at $1.5 billion. But $2 billion in fuel savings over Little Gypsy's expected life would more than compensate for the expenditure.

**Earnings are poised for another record year in 2008.** Wider margins on nuclear operations and a full year of the June, 2007 purchase of the Palisades nuclear plant will trigger most of the gain. Other pluses include fewer common shares outstanding and higher rates in three jurisdictions. All told, we estimate 2008 earnings will rise 18%, to $6.60 a share. Further gains are likely in the coming 3 to 5 years. The stock is timely.

**The separation provides investors with good growth potential.** Enexus will be able to engage in mergers and acquisitions more easily than it could as part of Entergy. Though the spinoff will reduce Entergy's cash flow, the $4 billion payment from Enexus will permit it to buy recently built merchant capacity and make transmission upgrades to access low-cost fuel. On balance, we rate the two parts greater than the whole.

*Arthur H. Medalie* *June 27, 2008*

(A) Dil. egs. Next egs. report due late July. Excl. nonrecur. gains (losses): '97, ($1.22); '98, 78¢; '01, 15¢; '02, ($1.04); '03, net 33¢; '05, (21¢). (B) Div'ds historically paid in early Mar., early June, early Sept., and early Dec. ■ Div. rein. plan avail. (C) Incl. def. chgs. In '07: $26.02/sh. (D) Rate base: net orig. cost. Rates allowed on com. eq.: 10.0%-13.0%. Earned on avg. com. eq. in '07: 14.1%. Reg. Clim.: Avg. (E) In mill.

| Company's Financial Strength | A |
|---|---|
| Stock's Price Stability | 95 |
| Price Growth Persistence | 95 |
| Earnings Predictability | 80 |

# EXELON CORP. NYSE-EXC

RECENT PRICE 73.73 | P/E RATIO 17.3 (Trailing: 18.4 Median: NMF) | RELATIVE P/E RATIO 1.12 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Raised 5/23/08
SAFETY 1 Raised 6/2/05
TECHNICAL 2 Raised 8/15/08
BETA .85 (1.00 = Market)

| | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
|---|---|---|---|---|---|---|---|---|---|
| High | 35.5 | 35.1 | 28.5 | 33.3 | 44.9 | 57.5 | 63.6 | 86.8 | 92.1 |
| Low | 26.9 | 19.4 | 18.9 | 23.0 | 30.9 | 41.8 | 51.1 | 58.7 | 70.0 |

Target Price Range 2011 | 2012 | 2013

**2011-13 PROJECTIONS**

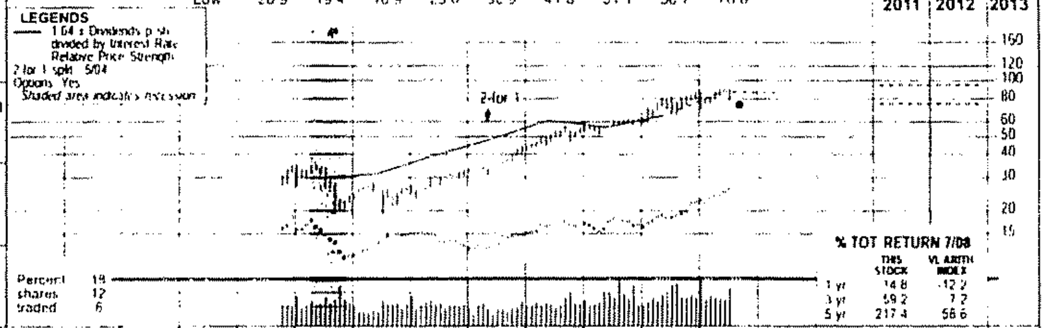
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 95 | (+30%) | 9% |
| Low | 75 | (Nil) | 3% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 5 | 0 | 11 | 3 | 0 | 0 | 3 | 0 |
| to Sell | 0 | 6 | 0 | 0 | 4 | 0 | 0 | 3 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 313 | 366 | 340 |
| to Sell | 303 | 278 | 333 |
| Hld's(000) | 452258 | 442191 | 434572 |




Exelon Corp. was formed on October 20, 2000 upon a merger of equals between PECO Energy Co. and Unicom Corp. (Unicom was the holding company for Commonwealth Edison Co.) PECO Energy stockholders received one common share in Exelon for each common share held. Unicom investors exchanged each of their common shares for .875 of an Exelon share and $3.00 in cash. Data in 2000 reflect PECO Energy and the addition of Unicom as of October 20th.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| -- | 19.40 | 11.75 | 23.58 | 23.13 | 23.89 | 21.85 | 23.06 | 23.37 | 28.62 | 29.25 | 31.00 | Revenues per sh | 39.50 |
| -- | 3.55 | 1.84 | 5.06 | 5.03 | 5.02 | 5.68 | 6.19 | 6.71 | 7.43 | 7.70 | 7.95 | "Cash Flow" per sh | 10.00 |
| -- | 1.86 | 1.39 | 2.20 | 2.40 | 2.44 | 2.75 | 3.21 | 3.50 | 4.03 | 4.15 | 4.30 | Earnings per sh A | 6.00 |
| -- | -- | -- | .91 | .88 | .96 | 1.26 | 1.60 | 1.64 | 1.82 | 2.02 | 2.10 | Div'd Decl'd per sh B ■ | 2.40 |
| -- | -- | 1.18 | 3.18 | 3.33 | 2.95 | 2.89 | 3.25 | 3.61 | 4.05 | 4.80 | 5.10 | Cap'l Spending per sh | 6.50 |
| -- | -- | 11.31 | 12.82 | 11.97 | 12.64 | 14.19 | 13.70 | 14.89 | 15.34 | 16.25 | 17.90 | Book Value per sh C | 24.25 |
| -- | 630.20 | 638.01 | 642.01 | 646.63 | 662.00 | 664.25 | 666.00 | 670.00 | 661.00 | 650.00 | 645.00 | Common Shs Outst'g D | 620.00 |
| -- | | 22.4 | 13.2 | 10.5 | 11.6 | 13.0 | 15.4 | 16.5 | 18.2 | Bold figures are Value Line estimates | | Avg Ann'l P/E Ratio | 14.5 |
| | | 1.46 | .68 | .57 | .67 | .69 | .82 | .89 | .97 | | | Relative P/E Ratio | .95 |
| | | -- | 3.1% | 3.5% | 3.4% | 3.5% | 3.2% | 2.8% | 2.5% | | | Avg Ann'l Div'd Yield | 2.8% |
| -- | 12225 | 7499.0 | 15140 | 14955 | 15812 | 14515 | 15357 | 15655 | 18916 | 19000 | 20000 | Revenues ($mill) | 24500 |
| -- | 1233.0 | 590.0 | 1465.0 | 1599.0 | 1641.0 | 1844.0 | 2162.0 | 2370.0 | 2730.0 | 2750 | 2840 | Net Profit ($mill) | 3865 |
| -- | 35.5% | 36.6% | 38.9% | 36.7% | 32.9% | 27.5% | 30.4% | 33.7% | 34.6% | 35.5% | 37.0% | Income Tax Rate | 37.0% |
| -- | -- | 5% | 1.2% | 1.2% | 1.9% | .9% | 1.0% | 1.6% | 1.8% | 1.0% | 1.0% | AFUDC % to Net Profit | 1.0% |
| -- | 35.5% | 62.3% | 59.3% | 61.2% | 61.1% | 56.1% | 56.1% | 54.2% | 53.9% | 55.5% | 52.0% | Long-Term Debt Ratio | 48.5% |
| -- | 10.1% | 34.7% | 37.9% | 36.1% | 38.5% | 43.5% | 43.5% | 45.4% | 45.7% | 44.0% | 47.5% | Common Equity Ratio | 51.0% |
| -- | -- | 20803 | 21719 | 21464 | 22079 | 21658 | 20972 | 21971 | 22189 | 23875 | 24400 | Total Capital ($mill) | 29400 |
| -- | -- | 12936 | 13742 | 17134 | 20630 | 21482 | 21981 | 22775 | 24153 | 25825 | 27525 | Net Plant ($mill) | 33200 |
| -- | -- | 4.1% | 9.0% | 9.4% | 9.2% | 10.4% | 12.1% | 12.5% | 14.1% | 13.0% | 13.0% | Return on Total Cap'l | 14.5% |
| | -- | 7.5% | 16.6% | 19.2% | 19.1% | 19.4% | 23.5% | 23.6% | 26.7% | 26.0% | 24.5% | Return on Shr. Equity | 25.5% |
| -- | -- | 7.8% | 17.2% | 20.1% | 16.8% | 19.5% | 23.6% | 23.7% | 26.9% | 26.0% | 24.5% | Return on Com Equity E | 26.0% |
| -- | -- | 7.8% | 13.1% | 12.8% | 11.5% | 10.7% | 11.9% | 13.0% | 15.3% | 13.5% | 13.0% | Retained to Com Eq | 16.0% |
| -- | -- | 4% | 43% | 38% | 40% | 45% | 50% | 45% | 43% | 48% | 46% | All Div'ds to Net Prof | 39% |

**CAPITAL STRUCTURE as of 6/30/08**
**Total Debt** $14754 mill. **Due in 5 Yrs** $6852 mill.
**LT Debt** $12641 mill. **LT Interest** $695 mill.
Includes $1548 mill. nonrecourse transition bonds.
(LT interest earned: 6.0x)
**Leases, Uncapitalized** Annual rentals $69.0 mill.
**Pension Assets-12/07** $9.63 bill. **Oblig.** $10.4 bill.
**Pfd Stock** $87.0 mill. **Pfd Div'd** $4.0 mill.
Includes $87.0 mill. in preferred securities of subsidiaries.
**Common Stock** 657,332,170 shs.

**MARKET CAP: $48 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +4.9 | -1.7 | +3.6 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 6.84 | 7.05 | 8.34 |
| Capacity at Peak (Mw) | 33520 | 33464 | NA |
| Peak Load (Mw) | 30261 | 32545 | NA |
| Nuclear Capacity Factor (%) | 93.5 | 93.9 | 94.5 |
| % Change Customers (yr-end) | +.7 | +1.1 | NA |
| Fixed Charge Cov. (%) | 461 | 466 | 516 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | -- | 5.0% | 8.0% |
| "Cash Flow" | -- | 11.0% | 6.5% |
| Earnings | -- | 12.5% | 9.0% |
| Dividends | -- | 23.0% | 6.0% |
| Book Value | -- | 4.0% | 9.0% |

| Calendar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 3561 | 3484 | 4473 | 3839 | 15357 |
| 2006 | 3861 | 3697 | 4401 | 3696 | 15655 |
| 2007 | 4829 | 4501 | 5032 | 4554 | 18916 |
| 2008 | 4517 | 4622 | 5250 | 4611 | 19000 |
| 2009 | 4800 | 4800 | 5600 | 4800 | 20000 |

| Calendar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .77 | .76 | 1.07 | .61 | 3.21 |
| 2006 | .59 | .95 | 1.09 | .87 | 3.50 |
| 2007 | 1.01 | 1.03 | 1.15 | .84 | 4.03 |
| 2008 | .88 | 1.13 | 1.15 | .99 | 4.15 |
| 2009 | 1.00 | 1.05 | 1.20 | 1.05 | 4.30 |

| Calendar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .275 | .275 | .305 | .40 | 1.26 |
| 2005 | .40 | .40 | .40 | .40 | 1.60 |
| 2006 | .40 | .40 | .40 | .40 | 1.60 |
| 2007 | .44 | .44 | .44 | .44 | 1.76 |
| 2008 | .50 | .50 | | | |

**BUSINESS:** Exelon Corporation is a holding company for Commonwealth Edison, which serves 3.8 million electric customers in Illinois, and PECO Energy, which serves 1.6 million electric and 480,000 gas customers in Pennsylvania. Markets energy in the mid-Atlantic and Midwest regions. Electric revenue breakdown, '07: residential, 47%; small commercial & industrial, 27%; large commercial & industrial, 17%; other, 9%. Generating sources, '07: nuclear, 74%; other, 6%; purchased, 20%. Fuel costs: 40% of revenues. '07 depreciation rate: 6.8%. Has 17,800 employees. Chairman, President & CEO: John W. Rowe. Inc.: Pennsylvania. Address: 10 South Dearborn St., P.O. Box 805398, Chicago, Illinois 60680-5398. Tel.: 312-394-7398. Internet: www.exeloncorp.com.

**Although Exelon is having a good year, we have reduced our earnings estimate for 2009.** The company's plants are performing well, particularly its fleet of 17 nuclear units. Effective hedging has enabled the company to lock in an attractive margin on its power sales. In fact, almost all of the company's expected power sales for 2008 and 2009 are hedged, as are over half of its expected sales for 2010. We're sticking with our 2008 earnings estimate of $4.15 a share, which would be above even the company's stellar showing a year earlier. But Exelon's hedging strategy, while protecting the company's profits in case the power markets turn unfavorable, is also limiting its upside potential in the near term. In addition, Exelon is facing inflationary pressures. Thus, our previous share-earnings estimate of $4.55 for 2009 appears overly optimistic. We have lowered it by $0.25, to $4.30.

**A big jump in earnings is likely in 2011.** That's when the electric customers of PECO Energy in Pennsylvania are scheduled to begin paying market-based rates for their power. Exelon is now supplying that power at a below-market price.

**Commonwealth Edison is asking the Illinois regulators for a rate hike.** Based on the terms of a partial settlement with the Illinois Commerce Commission's staff, the utility is seeking an increase of $314 million, based on a return of 10.75% on a common-equity ratio of 45.04%. The staff and an administrative law judge are recommending increases of $269 million and $218 million, respectively, based on a return of 10.3% on the same common-equity ratio. An order is due in September.

**PECO Energy has a gas rate case pending.** The utility is requesting a tariff hike of $98.3 million (11.2%), based on an 11.5% return on a 54.34% common-equity ratio. A decision is due in time for new rates to take effect at the start of 2009.

**We think this stock is fully valued.** Exelon's heavy nuclear presence should produce much higher earnings in the long run as the higher cost of gas and coal generation drives market prices upward. But the market is aware of this, and the stock is trading within our 2011-2013 Target Price Range. Total return potential over that time is unexceptional.

*Paul E. Debbas, CFA* *August 29, 2008*

(A) Diluted earnings. Excludes nonrecurring gains (losses): '01, 2¢; '02, (18¢); '03, ($1.06); '04, 3¢ net; '05, ($1.85) net; '06, ($1.15); gain from discontinued operations: '07, 2¢. Next earnings report due late October. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment program available. (C) Incl. deferred charges. In '07: $11.74/sh. (D) In mill., adj. for split. (E) Rate allowed on com. eq. in IL in '06: 10.045%; earned on avg. com. eq., '07: 26.7%. Regulatory Climate: PA, Average; IL, Below Average.

| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 90 |

# INTEGRYS ENERGY NYSE-TEG

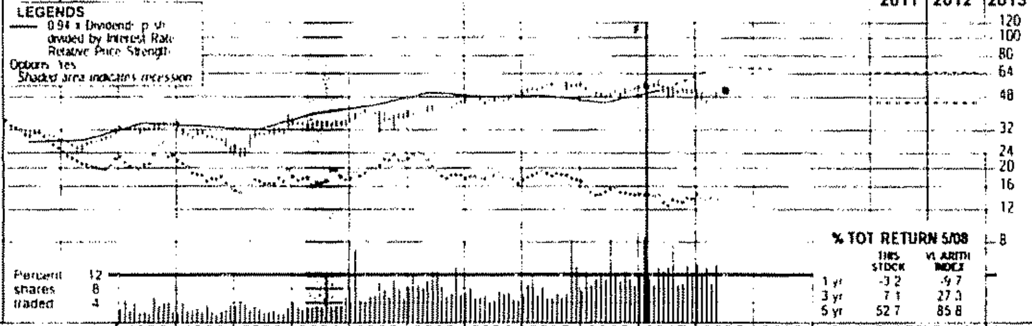
RECENT PRICE 52.12 | P/E RATIO 14.3 (Trailing: 20.4 / Median 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 5.2% | VALUE LINE

TIMELINESS — Suspended 3/30/07
SAFETY 2 Lowered 4/4/03
TECHNICAL — Suspended 3/30/07
BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 34.3 | 37.5 | 35.6 | 39.0 | 36.8 | 42.7 | 46.8 | 50.5 | 60.0 | 57.8 | 60.6 | 53.3 |
| Low | 23.4 | 29.9 | 24.4 | 22.6 | 31.0 | 30.5 | 36.8 | 43.5 | 47.7 | 47.4 | 48.1 | 44.0 |

Target Price Range
2011 | 2012 | 2013

LEGENDS
—— 0.94 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area indicates recession




**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+25%) | 10% |
| Low | 45 | (-15%) | 2% |

**Insider Decisions**

| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Options | 1 | 3 | 1 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 1 | 3 | 1 | 0 | 1 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 123 | 146 | 136 |
| to Sell | 145 | 124 | 145 |
| Hld's(000) | 40302 | 39075 | 37215 |

% TOT. RETURN 5/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -3.2 | -9.7 |
| 3 yr. | 7.1 | 27.3 |
| 5 yr. | 52.7 | 85.8 |

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS only.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 40.06 | 40.91 | 72.68 | 85.80 | 83.55 | 117.07 | 131.26 | 173.37 | 158.82 | 134.67 | 153.90 | 161.65 | Revenues per sh | 179.75 |
| 5.01 | 5.34 | 6.11 | 5.27 | 5.91 | 6.23 | 6.98 | 7.40 | 5.87 | 4.88 | 6.75 | 7.30 | "Cash Flow" per sh | 8.80 |
| 1.76 | 2.74 | 2.43 | 2.74 | 2.74 | 2.76 | 4.07 | 4.09 | 3.54 | 2.47 | 3.65 | 3.85 | Earnings per sh A | 4.35 |
| 1.96 | 2.00 | 2.04 | 2.08 | 2.12 | 2.16 | 2.20 | 2.24 | 2.28 | 2.56 | 2.68 | 2.72 | Div'd Decl'd per sh B■† | 2.84 |
| 3.57 | 4.93 | 5.94 | 7.98 | 7.16 | 4.77 | 7.78 | 10.31 | 7.88 | 5.14 | 7.10 | 7.05 | Cap'l Spending per sh | 6.20 |
| 19.48 | 19.97 | 20.21 | 22.96 | 24.45 | 27.18 | 29.30 | 32.47 | 35.35 | 42.34 | 43.40 | 44.60 | Book Value per sh C | 48.55 |
| 26.55 | 26.85 | 26.85 | 31.18 | 32.07 | 36.91 | 37.26 | 40.16 | 43.39 | 76.42 | 77.20 | 78.00 | Common Shs Outst'g D | 80.40 |
| 18.9 | 13.2 | 12.2 | 12.5 | 14.0 | 14.9 | 11.5 | 13.4 | 14.6 | 21.5 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | 12.5 |
| .98 | .75 | .79 | .64 | .76 | .85 | .61 | .71 | .79 | 1.13 | | | Relative P/E Ratio | .85 |
| 5.9% | 6.7% | 6.9% | 6.1% | 5.5% | 5.3% | 4.7% | 4.1% | 4.4% | 4.8% | | | Avg Ann'l Div'd Yield | 5.2% |
| 1063.7 | 1098.5 | 1951.6 | 2675.5 | 2674.9 | 4321.3 | 4890.6 | 6962.7 | 6890.7 | 10292 | 11880 | 12610 | Revenues ($mill) | 14450 |
| 49.8 | 62.7 | 67.4 | 83.7 | 94.4 | 94.5 | 156.2 | 157.4 | 151.6 | 181.0 | 285 | 300 | Net Profit ($mill) | 350 |
| 32.3% | 32.2% | 6.7% | 5.6% | 20.8% | 26.3% | 16.1% | 22.9% | 22.9% | 32.2% | 32.0% | 32.0% | Income Tax Rate | 32.0% |
| | | | -- | 3.2% | 2.5% | 1.7% | 1.0% | 4% | 5% | 2.0% | 2.0% | AFUDC % to Net Profit | 2.0% |
| 35.7% | 47.8% | 50.6% | 47.1% | 48.3% | 45.3% | 43.1% | 39.0% | 44.8% | 40.8% | 45.0% | 45.0% | Long-Term Debt Ratio | 47.0% |
| 53.8% | 43.9% | 41.6% | 46.3% | 45.8% | 52.1% | 54.4% | 58.7% | 53.4% | 58.3% | 54.0% | 54.0% | Common Equity Ratio | 52.5% |
| 961.4 | 1222.0 | 1303.9 | 1544.8 | 1708.3 | 1926.2 | 2008.6 | 2222.4 | 2871.9 | 5552.0 | 6205 | 6425 | Total Capital ($mill) | 7460 |
| 820.1 | 863.7 | 905.1 | 1463.6 | 1610.2 | 1828.7 | 2002.6 | 2049.4 | 2534.8 | 4463.8 | 4775 | 5055 | Net Plant ($mill) | 5615 |
| 6.4% | 6.2% | 6.8% | 6.8% | 7.0% | 6.1% | 8.8% | 8.0% | 6.4% | 4.5% | 6.0% | 6.0% | Return on Total Cap'l | 6.0% |
| 8.0% | 9.8% | 10.5% | 9.9% | 10.7% | 9.0% | 13.7% | 11.6% | 9.6% | 5.5% | 8.5% | 8.5% | Return on Shr. Equity | 9.0% |
| 9.0% | 11.1% | 11.9% | 10.8% | 11.7% | 9.1% | 14.0% | 11.8% | 9.7% | 5.5% | 8.5% | 8.5% | Return on Com Equity E | 9.0% |
| NMF | 1.2% | 1.9% | 2.7% | 3.1% | 2.0% | 6.6% | 5.3% | 3.4% | -- | 2.0% | 2.5% | Retained to Com Eq | 3.0% |
| 102% | 85% | 80% | 76% | 74% | 79% | 54% | 56% | 65% | 100% | 74% | 71% | All Div'ds to Net Prof | 66% |

**CAPITAL STRUCTURE as of 3/31/08**
Total Debt $2448 mill. Due in 5 Yrs $716 mill.
LT Debt $2263 mill. LT Interest $133.6 mill.
(LT interest earned: 3.4x)
**Leases, Uncapitalized** Annual rentals $6.3 mill.
**Pension Assets-12/07** $1220 mill. **Oblig.** $1110 mill.
**Pfd Stock** $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50, sinking fund began 11/1/79. All cumulative, $100 par.

**Common Stock** 76,424,095 shs. as of 5/6/08
**MARKET CAP: $4.0 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +7.4 | +6.0 | +.4 |
| Avg. Indust. Use (MWH) | 15851 | 16390 | 14680 |
| Avg. Indust. Revs. per KWH (¢) | 4.53 | 4.82 | 6.93 |
| Capacity at Peak (Mw) | 2681 | 2936 | 2184 |
| Peak Load, Summer (Mw) | 2189 | 2360 | 2305 |
| Annual Load Factor (%) | 75.0 | 75.0 | 73.5 |
| % Change Customers (yr-end) | +.8 | +1.0 | +.8 |
| Fixed Charge Cov. (%) | 234 | 236 | 215 |

**ANNUAL RATES**

| of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 16.5% | 14.0% | 2.5% |
| "Cash Flow" | 2.0% | 1.0% | 6.5% |
| Earnings | 4.5% | 5.0% | 4.5% |
| Dividends | 2.5% | 2.5% | 3.0% |
| Book Value | 6.5% | 10.5% | 5.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 1486.9 | 1327.5 | 1757.3 | 2391.0 | 6962.7 |
| 2006 | 1995.7 | 1475.3 | 1555.1 | 1864.6 | 6890.7 |
| 2007 | 2747 | 2362 | 2123 | 3060 | 10292 |
| 2008 | 3989 | 2460 | 2225 | 3206 | 11880 |
| 2009 | 4140 | 2600 | 2370 | 3500 | 12610 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 1.73 | .62 | 1.25 | .49 | 4.09 |
| 2006 | 1.44 | .97 | .63 | .50 | 3.54 |
| 2007 | 1.67 | d.53 | .14 | 1.19 | 2.47 |
| 2008 | 1.77 | .20 | .15 | 1.53 | 3.65 |
| 2009 | 1.85 | .23 | .17 | 1.60 | 3.85 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .545 | .545 | .555 | .555 | 2.20 |
| 2005 | .555 | .555 | .565 | .565 | 2.24 |
| 2006 | .565 | .565 | .575 | .575 | 2.28 |
| 2007 | .583 | .66 | .66 | .66 | 2.56 |
| 2008 | .67 | .67 | | | |

**BUSINESS:** Integrys Energy Group is a holding company for WPS Resources and Peoples Energy. Provides products and services in regulated and nonregulated markets. Regulated operations comprise four natural gas utilities and one electric utility in Wisconsin, Illinois, Michigan, and Minnesota. Also conducts nonregulated energy related businesses in the United States and Canada. Has about 1.6 million natural gas distribution customers, 485,000 electric customers. '07 depreciation rate: 3.4%. Estimated plant age: 11 years. Has 5,231 employees. Chairman, President, & Chief Executive Officer: Larry L. Weyers. Incorp.: WI. Address: 130 East Randolph Drive, Chicago, Illinois 60601. Telephone: 800-236-1551. Internet: www.integrysgroup.com.

**Integrys' WPS Resources subsidiary has filed for higher rates.** It seeks $106 million in increased electric rates and $11.7 million in higher posted gas tariffs. A major part of the request is for return of refunds paid to customers in 2006 and 2007 for which credit had been deferred. The application also asks to place the $752 million cost of the Weston 4 coal-fired unit in the rate base. Too, recovery is sought for expenses related to the environmental compliance program, which has installed emission control equipment that reduced the need to purchase nitrogen oxide credits. Finally, the petition asks for reimbursement of the $34 million purchase-power and O&M cost stemming from last December's Weston 3's outage due to a lightning strike. New rates should be effective on January 1, 2009.

**The company is adding wind power generation.** Management projects it will need more than 200 megawatts (mw) of renewable energy by 2015 to comply with regulatory requirements. To meet the deadline, it has signed a letter of intent to acquire a 150-megawatt portion of a wind project in Minnesota. Construction will start as soon as an interconnection schedule is established with the Midwest Independent System Operator. TEG has further agreed to pay $251 million for a 99-mw wind farm in an area of Iowa where high capacity offsets costs. The sale is expected to close shortly. Operation is targeted for late 2009.

**We look for solid earnings in the merged company's first full year of operation.** Synergy savings of $70 million will replace 2007's costs related to the acquisition of Peoples. Rate hikes in Illinois and Wisconsin are another plus. On the down side, increased debt offerings were necessary to achieve the merger. All told, we estimate 2008 earnings will rise more than 45%, to $3.65 a share. Single-digit gains are likely to 2011-2013. We have assigned the stock no Timeliness rank because of its short trading history.

**These shares offer an above-average yield.** And dividend growth prospects are in line with those of the group. Moreover, the stock's Safety rank is 2 (Above Average). Utility investors might take a look here.

*Arthur H. Medalie* *June 27, 2008*

(A) Diluted EPS. Excl. gains (losses): '97, 12¢; '00, 10¢; '02, 68¢; '03, 10¢; '04, (35¢); '06, (32¢); '07, $1.02. Next egs. rpt. due late July. (B) Div'ds historically paid late Mar., June, Sept., and Dec. 1Q'07 pay't pro-rata to 2/21/07. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $948.3 mill., $12.41/sh. (D) In millions. (E) Rate base: Net orig. cost. Rate all'd in Wisc. on com. eq. in '07: 10.9%; earned on avg. com. eq. '07: 7.4%. Reg. Clim.: Wisc. Above Avg; Ill. Below Avg. (F) Prior data for WPS only.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 60 |

# MDU RESOURCES NYSE-MDU

RECENT PRICE 31.26 | P/E RATIO 15.6 (Trailing: 16.2 Median: 14.0) | RELATIVE P/E RATIO 1.01 | DIV'D YLD 2.0% | VALUE LINE

TIMELINESS 2 Raised 5/30/08
SAFETY 1 Raised 8/17/01
TECHNICAL 2 Raised 8/8/08
BETA 1.00 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 9.9 | 12.8 | 12.1 | 14.7 | 17.0 | 14.9 | 16.2 | 18.5 | 24.8 | 27.0 | 31.8 | 35.3 |
| Low | 6.2 | 8.4 | 8.4 | 7.8 | 9.9 | 8.0 | 10.9 | 14.6 | 17.0 | 21.8 | 24.4 | 23.1 |

**2011-13 PROJECTIONS**

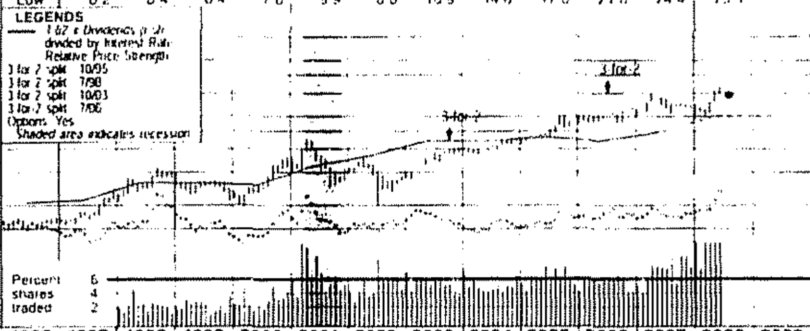
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+10%) | 5% |
| Low | 30 | (-5%) | 2% |

**Insider Decisions**

| | S | O | N | D | J | F | M | A | M |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 3 |
| to Sell | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 2 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 118 | 135 | 143 |
| to Sell | 135 | 128 | 132 |
| Hld's(000) | 87585 | 89630 | 91770 |




Target Price Range 2011 2012 2013: 64, 48, 40, 32, 24, 20, 16, 12, 8, 6

**% TOT. RETURN 6/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 26.9 | -18.0 |
| 3 yr. | 97.9 | 11.3 |
| 5 yr. | 164.0 | 63.2 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 3.67 | 4.57 | 4.68 | 4.83 | 5.36 | 6.40 | 7.51 | 9.97 | 12.81 | 14.16 | 12.03 | 13.83 | 15.33 | 19.21 | 22.49 | 23.22 | **26.10** | **27.15** | Revenues per sh | **31.25** |
| .77 | .87 | .91 | 1.00 | 1.12 | 1.26 | 1.27 | 1.29 | 1.51 | 1.84 | 1.74 | 2.16 | 2.37 | 2.80 | 3.25 | 3.41 | **3.75** | **3.95** | "Cash Flow" per sh | **4.75** |
| .36 | .40 | .41 | .42 | .47 | .55 | .64 | .68 | .80 | .98 | .62 | 1.05 | 1.20 | 1.53 | 1.75 | 1.76 | **2.00** | **2.05** | Earnings per sh A | **2.50** |
| .29 | .30 | .31 | .32 | .33 | .33 | .35 | .36 | .38 | .40 | .42 | .44 | .47 | .49 | .52 | .56 | **.60** | **.64** | Div'd Decl'd per sh B ■ † | **.76** |
| .74 | 1.07 | .85 | .87 | 1.16 | 1.18 | .81 | 1.29 | .84 | 1.35 | 1.66 | 1.84 | 1.90 | 2.84 | 2.81 | 3.05 | **4.05** | **3.95** | Cap'l Spending per sh | **4.25** |
| 3.16 | 3.31 | 3.40 | 3.51 | 3.65 | 4.07 | 4.62 | 5.22 | 6.02 | 7.07 | 7.71 | 8.44 | 9.39 | 10.43 | 11.88 | 13.75 | **14.90** | **16.25** | Book Value per sh C | **21.00** |
| 96.11 | 96.11 | 96.11 | 96.11 | 96.11 | 94.98 | 119.33 | 128.34 | 146.31 | 157.00 | 166.60 | 170.04 | 177.34 | 179.86 | 181.02 | 182.95 | **185.00** | **187.00** | Common Shs Outst'g D | **193.00** |
| 13.5 | 15.1 | 13.7 | 13.7 | 13.9 | 13.4 | 16.6 | 15.1 | 13.2 | 12.8 | 14.4 | 13.0 | 13.6 | 13.0 | 13.7 | 15.7 | *Bold figures are* | | Avg Ann'l P/E Ratio | **12.5** |
| .82 | .89 | .90 | .92 | .87 | .77 | .86 | .86 | .86 | .71 | .79 | .74 | .72 | .69 | .74 | .83 | *Value Line* | | Relative P/E Ratio | **.85** |
| 5.9% | 5.0% | 5.6% | 5.5% | 5.1% | 4.5% | 3.3% | 3.6% | 3.6% | 3.0% | 3.6% | 3.1% | 2.9% | 2.5% | 2.2% | 2.0% | *estimates* | | Avg Ann'l Div'd Yield | **2.4%** |
| | | | | | | 896.6 | 1279.8 | 1673.7 | 2223.6 | 2004.1 | 2352.2 | 2719.3 | 3455.4 | 4070.7 | 4247.9 | **4825** | **5080** | Revenues ($mill) | **6050** |
| | | | | | | 74.0 | 84.1 | 111.0 | 149.6 | 131.6 | 182.9 | 212.4 | 275.1 | 317.9 | 322.8 | **370** | **385** | Net Profit ($mill) | **490** |
| | | | | | | 37.1% | 37.0% | 38.5% | 38.6% | 36.4% | 35.0% | 30.9% | 34.6% | 34.2% | 37.1% | **37.0%** | **37.0%** | Income Tax Rate | **37.0%** |
| | | | | | | 4% | 2.1% | 4.7% | 4.4% | 5.8% | 1.4% | 2.9% | 4.2% | 2.6% | 2.2% | **2.0%** | **2.0%** | AFUDC % to Net Profit | **2.0%** |
| | | | | | | 42.1% | 45.1% | 44.8% | 41.0% | 38.7% | 39.3% | 34.2% | 36.9% | 35.1% | 31.2% | **34.5%** | **34.0%** | Long-Term Debt Ratio | **29.5%** |
| | | | | | | 56.2% | 53.6% | 54.2% | 58.1% | 60.6% | 60.1% | 65.2% | 62.6% | 64.5% | 68.4% | **65.0%** | **66.0%** | Common Equity Ratio | **70.5%** |
| | | | | | | 980.7 | 1249.6 | 1625.6 | 1909.8 | 2119.5 | 2390.1 | 2554.5 | 2996.4 | 3335.5 | 3678.1 | **4240** | **4620** | Total Capital ($mill) | **5775** |
| | | | | | | 1084.7 | 1248.2 | 1601.0 | 1809.3 | 1924.9 | 2222.3 | 2572.7 | 3049.9 | 2993.4 | 3659.6 | **4180** | **4565** | Net Plant ($mill) | **5750** |
| | | | | | | 8.8% | 8.2% | 8.4% | 9.2% | 7.3% | 8.7% | 9.5% | 10.2% | 10.7% | 9.8% | **9.5%** | **9.5%** | Return on Total Cap'l | **9.5%** |
| | | | | | | 13.0% | 12.3% | 12.4% | 13.3% | 10.1% | 12.6% | 12.6% | 14.5% | 14.7% | 12.8% | **13.5%** | **12.5%** | Return on Shr. Equity | **12.0%** |
| | | | | | | 13.3% | 12.4% | 12.5% | 13.4% | 10.2% | 12.7% | 12.7% | 14.6% | 14.8% | 12.8% | **13.5%** | **12.5%** | Return on Com Equity E | **12.0%** |
| | | | | | | 5.9% | 5.7% | 6.5% | 7.9% | 5.0% | 7.6% | 7.9% | 10.0% | 10.4% | 8.8% | **9.5%** | **8.5%** | Retained to Com Eq | **8.5%** |
| | | | | | | 56% | 55% | 49% | 41% | 52% | 40% | 38% | 32% | 29% | 31% | **30%** | **31%** | All Div'ds to Net Prof | **30%** |

**CAPITAL STRUCTURE as of 3/31/08**
Total Debt $1481.6 mill. Due in 5 Yrs $555.9 mill.
LT Debt $1270.0 mill. LT Interest $73.0 mill.
*(LT interest earned: 8.2x)*
**Leases, Uncapitalized** Annual rentals $20.3 mill.
**Pension Assets**-12/07 $331.0 mill. Oblig. $359.9 mill.
**Pfd Stock** $15.0 mill. Pfd Div'd $.7 mill.
50,000 shs. 4.7% cum. ($100 par), call. at $102;
100,000 shs. 4.5% ($100 par), call. at $105.
**Common Stock** 182,869,115 shs.
**as of 4/29/08**

**MARKET CAP: $5.7 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +4.6 | +2.9 | +4.8 |
| Avg. Indust. Use (MWH) | 1219 | 1268 | 1358 |
| Avg. Indust. Revs. per KWH (¢) | 4.57 | 4.70 | 4.83 |
| Capacity at Peak (Mw) | 546 | 547 | 571 |
| Peak Load, Summer (Mw) | 470 | 485 | 526 |
| Annual Load Factor (%) | 58.0 | 56.0 | NA |
| % Change Customers (avg.) | +.6 | +.6 | +.8 |
| Fixed Charge Cov. (%) | 663 | 651 | 690 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 14.5% | 10.5% | 6.5% |
| "Cash Flow" | 11.0% | 13.0% | 7.0% |
| Earnings | 13.5% | 14.0% | 7.0% |
| Dividends | 5.0% | 5.5% | 6.5% |
| Book Value | 12.5% | 11.5% | 9.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 604.3 | 770.2 | 1066.8 | 1014.1 | 3455.4 |
| 2006 | 814.8 | 973.2 | 1190.6 | 1092.1 | 4070.7 |
| 2007 | 787.5 | 982.4 | 1245.3 | 1232.7 | 4247.9 |
| 2008 | *1122* | ***1178*** | ***1275*** | ***1250*** | ***4825*** |
| 2009 | ***1155*** | ***1200*** | ***1375*** | ***1350*** | ***5080*** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .19 | .45 | .48 | .41 | 1.53 |
| 2006 | .29 | .39 | .61 | .45 | 1.75 |
| 2007 | .23 | .45 | .57 | .52 | 1.76 |
| 2008 | .39 | ***.51*** | ***.60*** | ***.50*** | ***2.00*** |
| 2009 | ***.30*** | ***.55*** | ***.65*** | ***.55*** | ***2.05*** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .113 | .113 | .113 | .12 | .46 |
| 2005 | .12 | .12 | .12 | .127 | .49 |
| 2006 | .127 | .127 | .127 | .135 | .52 |
| 2007 | .135 | .135 | .135 | .145 | .55 |
| 2008 | .145 | .145 | .145 | | |

**BUSINESS:** MDU Resources Group, Inc. is a diversified energy company. Montana-Dakota Utilities sells gas & electricity to 551,000 customers in ND, MT, SD, WY, MN, WA & OR. Electric rev. breakdown: '07: residential, 39%; commercial, 42%; industrial, 12%; other, 7%. Generating sources, '07: coal, 77%; other, 1%; purchased, 22%. Also has operations in gas pipelines, oil & gas production, aggregates mining, construction materials production, utility line construction & maintenance. Acq'd Cascade Natural Gas 7/07. '07 deprec. rate: 5.1%. Has 12,300 employees. Chairman: Harry J. Pearce. President & CEO: Terry D. Hildestad. Inc.: DE. Address: 1200 West Century Ave., P.O. Box 5650, Bismarck, ND 58506-5650. Tel.: 701-530-1000. Internet: www.mdu.com.

**MDU Resources is benefiting from high prices of oil and gas.** Production growth of 12%-16% is expected in 2008, with about half of the increase reflecting a big acquisition that took effect at the start of the year. The record level of oil prices is a big plus for the company, since MDU has hedged little of its expected oil production.
**The sputtering economy is hurting two of MDU's divisions.** Especially hard hit is the Construction Materials segment, where the normal seasonal loss in the first quarter more than doubled, to $21 million. The decline in residential construction has spilled over to affect commercial building. Although public works projects are picking up some of the slack, margins aren't as high as on private projects. The sharp rise in the cost of diesel fuel is a problem, too. Earnings in this operation are likely to decline for the full year. To a lesser extent, the economic weakness is also affecting the Construction Services unit, where MDU expects lower margins in 2008.
**Despite the strength in gas and oil prices, we have raised our 2008 and 2009 earnings estimates only slightly.** We figure that the weakness in the Construction Materials division will mitigate the strength in the Gas and Oil Production segment. We have boosted our 2008 and 2009 estimates by a dime a share, to $2.00 and $2.05, respectively.
**A utility acquisition is pending.** MDU plans to buy privately held Intermountain Gas, which serves over 300,000 customers in a fast-growing area in Idaho. The price, including the assumption of $80 million-$85 million of debt, is $328 million. The deal should close in the fourth quarter of 2008. It won't affect earnings much in the first year, but we will wait to adjust our figures until after it has closed, anyway.
**This timely stock has far outperformed the broad market averages so far this year.** This reflects the sharp rise in gas and oil prices. But MDU is hardly a pure play—this division generated 41% of operating income in 2007. That's material, but still less than half of corporate profits. Considering the falloff in Construction Materials (25% of operating income in 2007), we think the stock's run-up is excessive. In fact, the quotation is well within our 2011-2013 Target Price Range.

*Paul E. Debbas, CFA* *August 8, 2008*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '93, 6¢; '98, (34¢); '01, 4¢; '02, 10¢; '03, (5¢); '04, (3¢); gain (loss) on disc. ops.: '06, (1¢); '07, 60¢. '06 & '07 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $3.10/sh. (D) In mill., adj. for splits. (E) Rate base: varies. Rates all'd on com. eq.: 11.4%-13.0%; earned on avg. com. eq., '07: 14.1%. Regul. Climate: ND, MT Avg.; SD Above Avg.

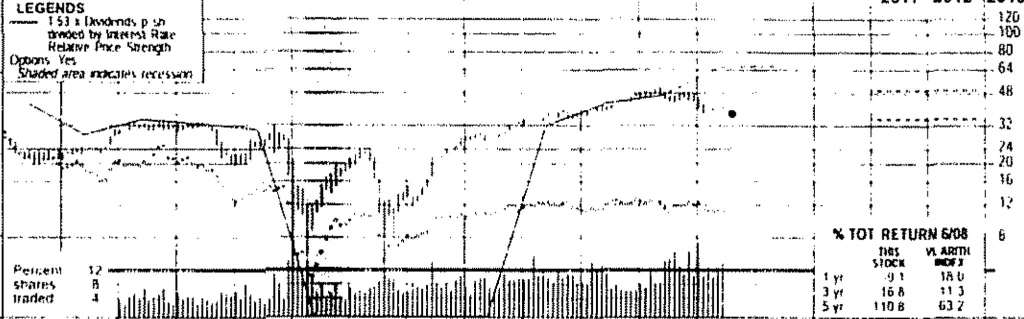
| | |
|---|---|
| Company's Financial Strength | A+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 95 |
| Earnings Predictability | 80 |

# PG&E CORP. NYSE-PCG

RECENT PRICE 37.31 | P/E RATIO 12.6 (Trailing: 13.9, Median: 15.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Raised 7/11/08
SAFETY 2 Raised 5/13/06
TECHNICAL 4 Lowered 7/25/08
BETA .85 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 30.9 | 35.1 | 34.0 | 31.8 | 20.9 | 23.8 | 28.0 | 34.5 | 40.1 | 48.2 | 52.2 | 45.7 |
| Low | 20.9 | 29.1 | 20.3 | 17.0 | 6.5 | 8.0 | 11.7 | 25.9 | 31.8 | 36.3 | 42.6 | 36.3 |




**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+35%) | 12% |
| Low | 35 | (-5%) | 4% |

**Insider Decisions**

| | S | O | N | D | J | F | M | A | M |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 1 | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 |
| to Sell | 1 | 0 | 0 | 0 | 12 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 170 | 199 | 171 |
| to Sell | 180 | 174 | 197 |
| Hld's(000) | 234682 | 237710 | 241884 |

**% TOT. RETURN 6/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -9.1 | 18.0 |
| 3 yr. | 16.8 | 11.3 |
| 5 yr. | 110.8 | 63.2 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 24.12 | 24.77 | 24.28 | 23.24 | 23.82 | 36.87 | 52.12 | 57.74 | 67.75 | 63.18 | 32.74 | 25.05 | 26.47 | 31.78 | 33.63 | 34.98 | 37.45 | 39.75 | Revenues per sh | 46.55 |
| 5.42 | 5.42 | 5.99 | 6.31 | 5.24 | 5.98 | 6.08 | 7.15 | .60 | 5.66 | 1.14 | 4.80 | 5.71 | 7.12 | 7.20 | 7.32 | 7.90 | 8.50 | "Cash Flow" per sh | 9.85 |
| 2.58 | 2.33 | 2.76 | 2.95 | 2.16 | 1.57 | 1.88 | 2.24 | d9.21 | 3.02 | d2.36 | 2.05 | 2.12 | 2.35 | 2.77 | 2.78 | 2.95 | 3.20 | Earnings per sh A | 3.50 |
| 1.76 | 1.88 | 1.96 | 1.96 | 1.77 | 1.20 | 1.20 | 1.20 | 1.20 | -- | -- | -- | -- | .90 | 1.32 | 1.41 | 1.56 | 1.68 | Div'd Decl'd per sh B■† | 2.04 |
| 5.41 | 4.13 | 2.54 | 2.25 | 3.05 | 4.36 | 4.23 | 4.39 | 4.54 | 7.33 | 7.94 | 4.08 | 3.72 | 4.90 | 6.44 | 7.32 | 9.95 | 7.30 | Cap'l Spending per sh | 7.10 |
| 19.41 | 19.77 | 20.07 | 20.77 | 20.73 | 21.30 | 21.08 | 19.10 | 8.19 | 11.89 | 9.47 | 10.12 | 20.62 | 19.60 | 20.95 | 22.60 | 24.10 | 25.70 | Book Value per sh C | 28.95 |
| 426.85 | 427.22 | 430.24 | 414.03 | 403.50 | 417.67 | 382.60 | 360.59 | 387.19 | 363.38 | 381.67 | 416.52 | 418.62 | 368.27 | 372.80 | 378.39 | 381.00 | 384.00 | Common Shs Outst'g D | 393.00 |
| 12.3 | 14.8 | 9.5 | 9.4 | 10.9 | 15.5 | 16.8 | 13.1 | -- | 4.8 | -- | 9.5 | 13.8 | 15.4 | 14.8 | 16.8 | Bold figures are | | Avg Ann'l P/E Ratio | 12.5 |
| .75 | .87 | .62 | .63 | .68 | .89 | .87 | .75 | -- | .25 | -- | .54 | .73 | .82 | .80 | .88 | Value Line | | Relative P/E Ratio | .85 |
| 5.6% | 5.5% | 7.5% | 7.1% | 7.5% | 4.9% | 3.8% | 4.1% | 4.8% | -- | -- | -- | -- | 2.5% | 3.2% | 3.0% | estimates | | Avg Ann'l Div'd Yield | 4.7% |

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 19942 | 20820 | 26232 | 22959 | 12495 | 10435 | 11080 | 11703 | 12539 | 13237 | 14270 | 15260 | Revenues ($mill) | 18300 |
| 746.0 | 825.0 | d3324 | 1099.0 | d874.0 | 791.0 | 901.0 | 904.0 | 991.0 | 1006.0 | 1125 | 1230 | Net Profit ($mill) | 1375 |
| 43.3% | 1.6% | -- | 35.6% | -- | 36.7% | 35.0% | 37.6% | 35.9% | 34.9% | 35.0% | 35.0% | Income Tax Rate | 35.0% |
| -- | -- | -- | 1.6% | -- | 3.7% | 3.6% | 5.6% | 6.8% | 9.5% | 8.0% | 5.0% | AFUDC % to Net Profit | 5.0% |
| 45.6% | 46.5% | 62.1% | 58.9% | 51.5% | 42.4% | 45.1% | 48.3% | 45.4% | 48.1% | 48.0% | 48.0% | Long-Term Debt Ratio | 48.0% |
| 49.6% | 48.0% | 30.4% | 34.9% | 42.8% | 53.9% | 53.2% | 50.0% | 52.9% | 50.4% | 50.5% | 50.5% | Common Equity Ratio | 51.0% |
| 16266 | 14339 | 10428 | 12399 | 8436.0 | 7815.0 | 16242 | 14446 | 14760 | 16976 | 18200 | 19480 | Total Capital ($mill) | 22310 |
| 17818 | 16776 | 16591 | 19167 | 16926 | 18107 | 18989 | 19955 | 21785 | 23656 | 25555 | 26305 | Net Plant ($mill) | 27655 |
| 6.5% | 7.4% | NMF | 13.3% | NMF | 16.3% | 7.6% | 8.1% | 8.4% | 8.0% | 8.0% | 8.5% | Return on Total Cap'l | 8.0% |
| 6.4% | 10.8% | NMF | 21.5% | NMF | 17.6% | 10.1% | 12.1% | 12.3% | 11.4% | 12.0% | 12.0% | Return on Shr. Equity | 11.5% |
| 6.9% | 11.6% | NMF | 22.9% | NMF | 18.5% | 10.3% | 12.3% | 12.5% | 11.7% | 12.0% | 12.5% | Return on Com Equity E | 11.5% |
| 3.4% | 5.2% | NMF | 22.9% | NMF | 18.5% | 10.3% | 7.7% | 6.6% | 5.9% | 5.5% | 6.0% | Retained to Com Eq | 5.0% |
| 63% | 56% | NMF | 10% | -- | 2% | 1% | 39% | 48% | 50% | 53% | 53% | All Div'ds to Net Prof | 58% |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $8553 mill. **Due in 5 Yrs** $2826 mill.
**LT Debt** $7721 mill. **LT Interest** $650.0 mill.
(LT interest earned: 3.1x)
**Pension Assets-12/07** $9.5 bill. **Oblig.** $9.1 bill.
**Pfd Stock** $252.0 mill. **Pfd Div'd** $16.0 mill.
5,973,456 shs. 4.36% to 7.04%, cum. and $25 par redeem. from $25.75 to $27.25; 5,784,825 shs. 5.00% to 6.00%, cum. nonredeem. and $25 par; 5,500,000 shs. 6.30% and 6.57%, cum. $25 par mandat. redempt.

**Common Stock** 378,385,151 shs.
**MARKET CAP: $14.1 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -1.6 | +5.8 | +2.2 |
| Avg. Indust. Use (MWH) | 12341 | 12536 | 12253 |
| Avg. Indust. Revs. per KWH (¢) | 8.15 | 8.60 | 8.34 |
| Capacity at Peak (Mw) | NMF | NMF | NMF |
| Peak Load, Summer (Mw) | NMF | NMF | NMF |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (yr-end) | -- | +2.7 | +2.0 |
| Fixed Charge Cov. (%) | 309 | 263 | 259 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 2.0% | -9.5% | 5.5% |
| "Cash Flow" | 2.0% | 23.5% | 5.5% |
| Earnings | 1.5% | -- | 5.0% |
| Dividends | -3.0% | -- | 9.0% |
| Book Value | -- | 16.5% | 5.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 2669 | 2498 | 2804 | 3732 | 11703 |
| 2006 | 3148 | 3017 | 3168 | 3206 | 12539 |
| 2007 | 3356 | 3187 | 3279 | 3415 | 13237 |
| 2008 | 3733 | 3380 | 3500 | 3657 | 14270 |
| 2009 | 3980 | 3630 | 3750 | 3900 | 15260 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .54 | .70 | .62 | .49 | 2.35 |
| 2006 | .60 | .65 | 1.09 | .43 | 2.77 |
| 2007 | .71 | .74 | .77 | .56 | 2.78 |
| 2008 | .62 | .78 | .95 | .60 | 2.95 |
| 2009 | .70 | .85 | 1.00 | .65 | 3.20 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | -- | -- | -- | -- | -- |
| 2005 | -- | .30 | .30 | .30 | .90 |
| 2006 | .33 | .33 | .33 | .33 | 1.32 |
| 2007 | .33 | .36 | .36 | .36 | 1.41 |
| 2008 | .36 | .39 | .39 | | |

**BUSINESS:** PG&E Corporation is a holding co. for Pacific Gas and Electric Company and nonutil. subsids. Supplies electricity and gas in 48 Calif. counties. Owns generation elsewhere in the U.S. Elect. (and gas) rev. breakdown: resid., 36% (75%); commer., 39% (25%); indust., 18% (under 1%); other, 7%. Petroleum refining industry is the largest elect. and gas customer. '07 megawatt capacity: hydro, 62%; fossil fuels, 2%; nuclear, 36%. Fuel costs: 41% of utility revenues. labor costs (system): 15%. '07 deprec. rate: 3.3%. Est'd plant age: 9 years. Has 20,050 employees. Chairman, President & Chief Executive Officer: Peter A. Darbee. Inc.: Calif. Address: 77 Beale Street, San Francisco, Calif. 94106. Tel.: 1-800-367-7731. Internet: www.pgecorp.com.

**PG&E plans to expand its gas transmission system.** It has agreed to acquire a 25.5% stake in El Paso Corp's proposed 680-mile natural gas pipeline that will run from Wyoming to a terminal in Oregon near California's northern border. The line's initial capacity of 1.2 billion cubic feet per day (bcf/d) is expandable to two bcf/d. The cost is estimated at $2 billion. Regulatory approvals are needed before ground breaking. Too, PG&E and two equal partners expect to build a 223-mile line with a capacity of one bcf/d on a yet-to-be determined route between Oregon and the California Bay area. Portions are targeted for operation in 2011, the balance by 2013. The output of these lines will help meet the growing demand for natural gas in the western United States.

**The company is also enlarging its generation portfolio.** PG&E is spending $370 million to finish building the partially complete 530-megawatt (mw) gas-fired Gateway plant, which it acquired for $300 million. Operation is scheduled for 2009. Construction has also begun on the 660-mw gas-fired Colusa station, which should begin serving customers in early 2011. Furthermore, repowering of the Humboldt Bay 163-mw gas- and oil-facility, which had been near the end of its useful life, is under way. Finally, PG&E will buy the output of 285 mw of wind and from 500 mw to 900 mw of solar energy when available. These additions should be adequate to cover customer needs for years to come.

**Earnings should improve for the sixth consecutive year in 2008.** Results will be boosted by a full year of the $243 million 2007 rate order, an attrition adjustment of $125 million, and new plants on line. These positives will be partly offset by the cost of installing new steam generators in the Diablo Canyon 2 nuclear plant and higher interest expense. In all, we estimate 2008 earnings will rise 6%, to $2.95 a share. An order on a pending request for a $482 million rate hike suggests better results next year.

**The year-ahead yield mirrors the industry average.** But dividend growth prospects exceed those of the group, and finances are now comparable to those of pre-bankruptcy days. Utility investors might consider taking a position here.

*Arthur H. Medalie* *August 8, 2008*

(A) EPS diluted. Excl. nonrecurring gains (losses): '94, (55¢); '95, 4¢; '96, (41¢); '97, 18¢; '99, ($2.44); '04, $6.95. Incl. '00 nonrecurring loss: $11.83. Next earnings report due early Aug. (B) Dividends historically paid in mid-Jan., Apr., July, Oct. ■ Dividend reinvestment plan available. † Shareholder investment plan available. (C) Incl. intang. in '07: $11.89/sh. (D) In millions. (E) Rate base: net orig. cost. Rate allowed on com. eq. in '07: 11.35%. Earned on avg. com. eq. in '07: 12.3%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 55 |
| Earnings Predictability | 5 |

# P.S. ENTERPRISE GP. NYSE-PEG

RECENT PRICE 39.39 | P/E RATIO 13.2 (Trailing: 13.6; Median: 13.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.4% | VALUE LINE

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 15.9 | 21.4 | 21.3 | 25.0 | 25.8 | 23.6 | 22.3 | 26.3 | 34.2 | 36.3 | 49.9 | 52.3 |
| Low | 11.4 | 15.2 | 16.0 | 12.8 | 18.4 | 10.0 | 16.0 | 19.0 | 24.7 | 29.5 | 32.2 | 38.3 |

Target Price Range 2011 | 2012 | 2013

TIMELINESS 3 Raised 4/27/07
SAFETY 3 Lowered 3/7/03
TECHNICAL 3 Raised 8/1/08
BETA .85 (1.00 = Market)

**2011-13 PROJECTIONS**

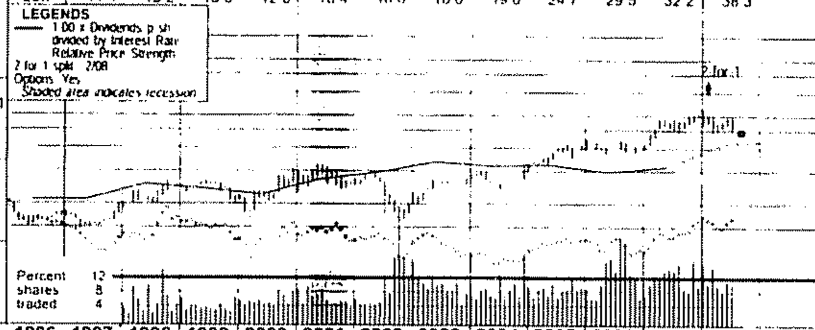
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+25%) | 10% |
| Low | 35 | (-10%) | 2% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 2 |
| to Sell | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 2 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 178 | 268 | 202 |
| to Sell | 186 | 143 | 243 |
| Hld's(000) | 306664 | 305764 | 308984 |




**% TOT. RETURN 7/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr | -0.3 | 12.2 |
| 3 yr | 42.7 | 7.2 |
| 5 yr | 147.9 | 58.6 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 11.36 | 11.71 | 12.09 | 12.60 | 12.94 | 13.73 | 12.78 | 15.01 | 22.83 | 23.84 | 18.62 | 23.54 | 23.09 | 24.74 | 22.83 | 25.28 | *26.05* | *27.10* | Revenues per sh | *30.30* |
| 2.34 | 2.57 | 2.67 | 2.73 | 2.58 | 2.57 | 2.83 | 2.82 | 2.71 | 3.14 | 3.01 | 2.92 | 3.02 | 3.19 | 2.97 | 4.13 | *4.70* | *5.05* | "Cash Flow" per sh | *5.90* |
| .99 | 1.36 | 1.39 | 1.36 | 1.23 | 1.21 | 1.40 | 1.56 | 1.78 | 1.35 | 1.88 | 1.88 | 1.52 | 1.79 | 1.50 | 2.59 | *2.95* | *3.15* | Earnings per sh [A] | *3.45* |
| 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.10 | 1.12 | 1.14 | 1.17 | *1.29* | *1.41* | Div'd Decl'd per sh [B]■† | *1.65* |
| 1.70 | 1.77 | 1.74 | 1.59 | 1.25 | 1.17 | 1.15 | 1.34 | 2.31 | 4.99 | 4.03 | 2.86 | 2.64 | 2.04 | 1.91 | 2.65 | *2.55* | *3.20* | Cap'l Spending per sh | *3.20* |
| 10.16 | 10.53 | 10.85 | 11.13 | 11.16 | 11.23 | 10.99 | 9.23 | 9.61 | 10.05 | 8.85 | 11.71 | 12.05 | 11.99 | 12.66 | 14.35 | *16.10* | *18.00* | Book Value per sh [C] | *23.75* |
| 470.79 | 487.38 | 489.40 | 489.40 | 466.94 | 463.92 | 463.92 | 432.83 | 415.94 | 411.68 | 450.53 | 472.27 | 476.20 | 502.33 | 532.74 | 508.52 | *510.00* | *512.00* | Common Shs Outst'g [E] | *518.00* |
| 14.1 | 12.3 | 9.9 | 10.4 | 11.2 | 10.9 | 12.7 | 12.5 | 10.3 | 12.0 | 10.0 | 10.6 | 14.0 | 16.4 | 22.0 | 16.5 | *Bold figures are* | | Avg Ann'l P/E Ratio | *12.0* |
| .86 | .73 | .65 | .70 | .70 | .63 | .66 | .71 | .67 | .61 | .55 | .60 | .76 | .87 | 1.19 | .87 | *Value Line* | | Relative P/E Ratio | *.80* |
| 7.8% | 6.5% | 7.9% | 7.6% | 7.8% | 8.2% | 6.1% | 5.5% | 5.9% | 4.9% | 5.7% | 5.4% | 5.1% | 3.8% | 3.5% | 2.7% | *estimates* | | Avg Ann'l Div'd Yield | *3.7%* |

**CAPITAL STRUCTURE as of 6/30/08**
**Total Debt $10035 mill Due in 5 Yrs $5750 mill**
**LT Debt $8281 mill LT Interest $617 mill**
(LT interest earned: 4.3x)
**Pension Assets-12/07 $3.39 bill Oblig. $3.60 bill**
**Pfd Stock $80.0 mill Pfd Div'd $4.0 mill**
795,234 shs. 4.08% to 6.92%, cum. $100 par, call from $102.75 to $103.00 a sh.

**Common Stock 508,480,898 shs**
Adj. for 2-for-1 split 2/5/08
**MARKET CAP: $20.0 billion (Large Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 5931.0 | 6497.0 | 9498.0 | 9815.0 | 8390.0 | 11116 | 10996 | 12430 | 12164 | 12853 | *13290* | *13880* | Revenues ($mill) | *15700* |
| 724.0 | 780.0 | 858.0 | 842.0 | 842.8 | 856.0 | 725.0 | 858.0 | 756.0 | 1323.0 | *1505* | *1615* | Net Profit ($mill) | *1790* |
| 36.7% | 41.9% | 36.4% | 30.7% | 22.7% | 35.2% | 38.1% | 38.7% | 37.5% | 44.5% | *38.0%* | *38.0%* | Income Tax Rate | *38.0%* |
| 1.8% | -- | -- | -- | -- | -- | -- | 1% | 3% | 2.5% | *3.0%* | *3.0%* | AFUDC % to Net Profit | *3.0%* |
| 43.3% | 46.8% | 50.4% | 67.8% | 67.1% | 69.8% | 69.0% | 64.9% | 60.3% | 54.0% | *50.5%* | *49.5%* | Long-Term Debt Ratio | *49.5%* |
| 45.8% | 40.9% | 38.1% | 27.2% | 24.3% | 29.8% | 30.6% | 34.6% | 39.2% | 45.5% | *49.0%* | *50.0%* | Common Equity Ratio | *50.0%* |
| 11119 | 9779.0 | 10501 | 15198 | 16378 | 18554 | 18744 | 17381 | 17197 | 16041 | *16825* | *18415* | Total Capital ($mill) | *24515* |
| 10876 | 7078.0 | 7702.0 | 10064 | 11449 | 12422 | 13750 | 13336 | 13002 | 13275 | *13695* | *14360* | Net Plant ($mill) | *15880* |
| 8.2% | 9.5% | 9.8% | 7.4% | 7.2% | 6.7% | 6.0% | 7.0% | 6.5% | 10.2% | *11.0%* | *10.5%* | Return on Total Cap'l | *9.0%* |
| 11.5% | 15.0% | 16.5% | 17.2% | 15.6% | 15.3% | 12.5% | 14.1% | 11.1% | 17.9% | *18.0%* | *17.5%* | Return on Shr. Equity | *14.5%* |
| 12.6% | 17.2% | 19.1% | 18.6% | 19.7% | 15.4% | 12.6% | 14.2% | 11.1% | 18.1% | *18.5%* | *17.5%* | Return on Com Equity [D] | *14.5%* |
| 2.8% | 5.3% | 7.5% | 7.8% | 8.3% | 6.5% | 3.5% | 5.2% | 2.6% | 9.9% | *10.0%* | *9.5%* | Retained to Com Eq | *7.5%* |
| 80% | 73% | 65% | 62% | 61% | 58% | 73% | 64% | 76% | 45% | *44%* | *45%* | All Div'ds to Net Prof | *48%* |

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.4 | -2.6 | +2.4 |
| Avg. Indust. Use (MWH) | NA | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | NA | NA | NA |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | NA | NA | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.0 | +1.0 | +1.0 |
| Fixed Charge Cov. (%) | 242 | 237 | 415 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 6.5% | 2.0% | *4.0%* |
| "Cash Flow" | 2.5% | 3.0% | *9.5%* |
| Earnings | 4.5% | 1.5% | *10.0%* |
| Dividends | .5% | 1.0% | *6.5%* |
| Book Value | 1.5% | 6.5% | *10.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 3243 | 2384 | 3331 | 3472 | 12430 |
| 2006 | 3461 | 2556 | 3212 | 2935 | 12164 |
| 2007 | 3508 | 2718 | 3356 | 3271 | 12853 |
| 2008 | 3803 | 2561 | *3500* | *3426* | *13290* |
| 2009 | *3950* | *2700* | *3650* | *3580* | *13880* |

| Cal-endar | EARNINGS PER SHARE [A] Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .59 | .19 | .56 | .45 | 1.79 |
| 2006 | .42 | d.01 | .75 | .34 | 1.50 |
| 2007 | .63 | .56 | .96 | .44 | 2.59 |
| 2008 | .85 | .64 | *1.00* | *.46* | *2.95* |
| 2009 | *.88* | *.67* | *1.10* | *.50* | *3.15* |

| Cal-endar | QUARTERLY DIVIDENDS PAID [B] ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .275 | .275 | .275 | .275 | 1.10 |
| 2005 | .28 | .28 | .28 | .28 | 1.12 |
| 2006 | .285 | .285 | .285 | .285 | 1.14 |
| 2007 | .293 | .293 | .293 | .293 | 1.17 |
| 2008 | .323 | .323 | | | |

**BUSINESS:** Public Service Enterprise Group Inc. is an exempt public utility holding company, with four wholly-owned subsidiaries: Public Service Electric and Gas Company, Power (a wholesale energy supply co.), Energy Holdings (a power producer domestically and abroad), and PSEG Services. Principal electric industrial customers: chemical and allied products, petroleum refining. Power costs: 57% of revenues. 2007 deprec. rate: 2.5%. Estimated plant age: 9 years. Has 9,857 employees. Starting in 2002, no longer breaks down data on electric and gas operating statistics. Chairman, Chief Executive Officer & President: Ralph Izzo. Incorp.: New Jersey. Address: 80 Park Plaza, Newark, New Jersey 07101. Tel.: 973-430-6564. Internet: www.pseg.com.

**Public Service Enterprise Group keeps selling foreign assets.** Last month, it sold its electricity and transmission business in Chile for $870 million in cash. After deducting Chilean and U.S. taxes, proceeds will be about $600 million, of which a portion will be applied to debt reduction. The sale will generate an after-tax gain of $170 million to $180 million, which we exclude from our earnings presentation because it's a nonrecurring item. PEG's remaining international holdings consist of small electric plants in Italy, India, and Venezuela, with a combined capacity of 173 megawatts (mw). The sale of these plants is planned because they do not fit in with overall strategy. But they will not be disposed of at bargain prices.

**Meanwhile, domestic operations are in a growth mode.** On the transmission front, plans call for construction of three 500-kilovolt lines in central and northern New Jersey to relieve power congestion in that area. PEG expects to invest $1.6 billion in the undertaking over the next five to eight years. The lines, which are still in planning stages, will run largely over existing rights of way to minimize disruption to municipalities. On the generation side, PEG is considering the addition of 1,000 mw of gas-fired plants and expects to spend $100 million in the next two years on loans to developers of solar systems in homes and businesses.

**We look for steady earnings gains for the next few years.** Nuclear operations are performing well under new management, and the sale of foreign assets is reducing risk. Too, higher prices for energy output are widening margins, and debt reductions are lowering interest expense. Note: Our 2008 presentation excludes a $0.96 per/share charge in the second quarter related to an IRS challenge of certain leveraged lease transactions in 2001 through 2003, because of their one-time nature. All told, we estimate current-year earnings will rise 14%, to $2.95 a share. Further improvement is likely in 2009.

**The stock price has stabilized since the sharp run-up in 2007.** The recent quote already reflects the market's projection of earnings and dividend growth to 2011-2013, in our opinion. At this juncture, PEG is an average utility selection.

*Arthur H. Medalie* *August 29, 2008*

(A) EPS basic. Excl. nonrecur. gains (losses): '92, 10¢; '93, (11¢); '95, 5¢; '96, 3¢; '99, net ($1.75); '02, ($1.30); '03, $68; '05, (41¢); '08, (96¢). Next earnings report due late Oct. (B) Div'ds historically paid in late March, late June, late Sept., and late Dec. ■ Div'd reinvest. plan available. † Shareholder investment plan avail. (C) Incl. intangibles. In '07: $10.29/sh. (D) Rate base: net original cost. Rate allowed on com. eq. in '03: 9.75%; earned on '07 avg. com. eq., 19.0%. Regul. Clim.: Average. (E) In mill.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 90 |
| Price Growth Persistence | 80 |
| Earnings Predictability | 65 |

# SCANA CORP. NYSE-SCG

RECENT PRICE 37.89 | P/E RATIO 12.6 (Trailing 12.8 / Median 14.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 5.0% | VALUE LINE

TIMELINESS 3 Raised 12/21/07
SAFETY 2 Lowered 9/10/99
TECHNICAL 3 Raised 7/25/08
BETA .80 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 29.9 | 37.3 | 32.6 | 31.1 | 30.0 | 32.1 | 35.7 | 39.7 | 43.7 | 42.4 | 45.5 | 42.7 |
| Low | 23.4 | 27.9 | 21.1 | 22.0 | 24.3 | 23.5 | 28.1 | 32.8 | 36.6 | 36.9 | 32.9 | 35.0 |

Target Price Range 2011 2012 2013

**2011-13 PROJECTIONS**

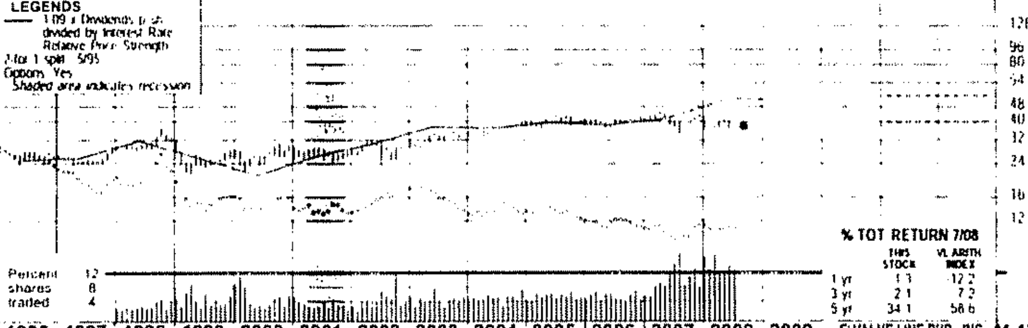
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 55 | (+45%) | 13% |
| Low | 40 | (+5%) | 6% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 2 | 0 | 1 | 0 | 0 | 0 | 1 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 113 | 148 | 150 |
| to Sell | 121 | 116 | 120 |
| Hld's(000) | 50378 | 53086 | 54874 |




**% TOT. RETURN 7/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr | 1.3 | -12.2 |
| 3 yr | 2.1 | 7.2 |
| 5 yr | 34.1 | 58.6 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12.96 | 13.56 | 13.77 | 13.06 | 14.25 | 14.19 | 15.76 | 15.93 | 32.78 | 32.95 | 26.65 | 30.85 | 34.38 | 41.54 | 39.00 | 39.50 | **44.90** | **43.35** | Revenues per sh | **47.75** |
| 2.78 | 3.50 | 3.77 | 3.68 | 3.75 | 3.53 | 3.62 | 3.15 | 4.43 | 4.55 | 4.56 | 4.95 | 5.26 | 7.41 | 5.67 | 5.72 | **5.85** | **5.95** | "Cash Flow" per sh | **6.75** |
| 1.42 | 1.86 | 1.60 | 1.86 | 2.05 | 1.90 | 2.12 | 1.44 | 2.12 | 2.15 | 2.38 | 2.50 | 2.67 | 2.78 | 2.59 | 2.74 | **3.00** | **3.10** | Earnings per sh A | **3.50** |
| 1.34 | 1.37 | 1.41 | 1.44 | 1.47 | 1.51 | 1.54 | 1.32 | 1.15 | 1.20 | 1.30 | 1.38 | 1.46 | 1.56 | 1.68 | 1.76 | **1.84** | **1.92** | Div'd Decl'd per sh B ■ † | **2.10** |
| 3.16 | 3.46 | 4.21 | 3.09 | 2.34 | 2.45 | 2.87 | 2.37 | 3.28 | 4.99 | 6.41 | 6.94 | 4.84 | 3.37 | 4.50 | 6.20 | **9.10** | **9.60** | Cap'l Spending per sh | **11.00** |
| 13.23 | 14.30 | 14.69 | 15.00 | 15.86 | 16.66 | 16.86 | 20.27 | 9.40 | 20.95 | 19.64 | 20.82 | 21.69 | 23.28 | 24.32 | 25.30 | **26.60** | **28.30** | Book Value per sh C | **33.50** |
| 87.82 | 93.24 | 96.04 | 103.62 | 106.18 | 107.32 | 103.57 | 103.57 | 104.73 | 104.73 | 110.83 | 110.74 | 113.00 | 115.00 | 117.00 | 117.00 | **118.00** | **124.00** | Common Shs Outst'g D | **134.00** |
| 14.5 | 12.8 | 14.0 | 12.3 | 13.1 | 13.4 | 14.5 | 17.5 | 12.5 | 12.6 | 12.2 | 13.0 | 13.6 | 14.4 | 15.4 | 15.0 | *Bold figures are* | | Avg Ann'l P/E Ratio | **13.5** |
| .88 | .76 | .92 | .82 | .82 | .77 | .75 | 1.00 | .81 | .65 | .67 | .74 | .72 | .77 | .83 | .80 | *Value Line* | | Relative P/E Ratio | **.90** |
| 6.5% | 5.8% | 6.3% | 6.3% | 5.5% | 5.9% | 5.0% | 5.2% | 4.3% | 4.4% | 4.5% | 4.2% | 4.0% | 3.9% | 4.2% | 4.3% | *estimates* | | Avg Ann'l Div'd Yield | **4.5%** |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $3865.0 mill **Due in 5 Yrs** $1655.0 mill
**LT Debt** $3276.0 mill **LT Interest** $197.0 mill
(LT interest earned: 3.3x)
**Leases, Uncapitalized** Annual rentals $16.0 mill
**Pension Assets**-12/07 $929.5 mill **Oblig.** $704.8 mill
**Pfd Stock** $113.0 mill **Pfd Div'd** $7.0 mill
125,209 shs 5% cum $50 par callable $52.50
220,287 shs 4.50% to 6.00% cum., $50 par callable $50.50 to $51.00, 1,000,000 shs 6.52% cum $100 par, callable $100.00
**Common Stock** 116,664,933 shs **as of 4/30/08**
**MARKET CAP: $4.4 billion (Mid Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1632.0 | 1650.0 | 3433.0 | 3451.0 | 2954.0 | 3416.0 | 3885.0 | 4777.0 | 4563.0 | 4621.0 | **5300** | **5500** | Revenues ($mill) | **6400** |
| 235.0 | 160.0 | 228.0 | 231.0 | 259.0 | 285.0 | 305.0 | 323.0 | 306.0 | 327.0 | **360** | **380** | Net Profit ($mill) | **485** |
| 35.8% | 41.0% | 38.2% | 34.9% | 32.2% | 31.5% | 32.5% | -- | 26.5% | 29.2% | **36.5%** | **36.5%** | Income Tax Rate | **36.5%** |
| 6.8% | 4.4% | 3.9% | 11.3% | 13.5% | 10.5% | 8.5% | 9% | 2.6% | 4.6% | **6.0%** | **8.0%** | AFUDC % to Net Profit | **8.0%** |
| 45.9% | 40.8% | 57.4% | 53.9% | 55.7% | 57.1% | 55.4% | 51.4% | 50.9% | 48.4% | **51.0%** | **50.0%** | Long-Term Debt Ratio | **50.0%** |
| 49.4% | 54.8% | 40.3% | 43.8% | 42.1% | 40.8% | 42.6% | 46.6% | 47.2% | 49.7% | **47.5%** | **48.5%** | Common Equity Ratio | **48.5%** |
| 3536.0 | 3829.0 | 5048.0 | 5306.0 | 5176.0 | 5646.0 | 5752.0 | 5739.0 | 6027.0 | 5952.0 | **6630** | **7230** | Total Capital ($mill) | **9225** |
| 3764.0 | 3829.0 | 4475.0 | 4803.0 | 5474.0 | 6417.0 | 6762.0 | 6734.0 | 7007.0 | 7538.0 | **8275** | **9105** | Net Plant ($mill) | **12225** |
| 8.4% | 5.9% | 6.8% | 6.9% | 7.0% | 6.9% | 7.1% | 7.4% | 6.8% | 7.3% | **7.0%** | **6.5%** | Return on Total Cap'l | **6.5%** |
| 12.3% | 7.1% | 10.6% | 10.0% | 11.3% | 11.6% | 11.9% | 11.6% | 10.3% | 10.6% | **11.0%** | **10.5%** | Return on Shr. Equity | **10.5%** |
| 12.8% | 7.1% | 10.9% | 10.2% | 11.6% | 12.1% | 12.2% | 11.8% | 10.5% | 10.8% | **11.0%** | **10.5%** | Return on Com Equity E | **10.5%** |
| 3.4% | -- | 4.8% | 4.6% | 5.5% | 5.5% | 5.6% | 5.3% | 3.8% | 4.0% | **4.5%** | **4.0%** | Retained to Com Eq | **4.5%** |
| 74% | 99% | 57% | 56% | 54% | 55% | 55% | 56% | 65% | 64% | **62%** | **63%** | All Div'ds to Net Prof | **59%** |

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +.9 | 1.4 | +2.6 |
| Avg. Indust. Use (MWH) | 13249 | 12005 | 9815 |
| Avg. Indust. Revs. per KWH (¢) | 4.87 | 5.16 | 5.30 |
| Capacity at Yearend (Mw) | 5776 | 5749 | 5688 |
| Peak Load, Summer (Mw) | 4820 | 4747 | 4926 |
| Annual Load Factor (%) | 57.3 | 57.5 | 56.7 |
| % Change Customers (yr-end) | +3.1 | +2.2 | +2.5 |
| Fixed Charge Cov. (%) | 190 | 261 | 272 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 11.0% | 5.5% | 3.0% |
| "Cash Flow" | 5.5% | 7.0% | 1.5% |
| Earnings | 3.5% | 4.0% | 4.5% |
| Dividends | 1.0% | 6.5% | 4.0% |
| Book Value | 4.5% | 4.0% | 5.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 1266 | 891.0 | 1127 | 1493 | 4777.0 |
| 2006 | 1389 | 944.0 | 1062 | 1168 | 4563.0 |
| 2007 | 1363 | 1007 | 1079 | 1172 | 4621.0 |
| 2008 | 1533 | 1218 | **1249** | **1300** | **5300** |
| 2009 | **1600** | **1250** | **1300** | **1350** | **5500** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .89 | .36 | .88 | .65 | 2.78 |
| 2006 | .80 | .46 | .76 | .57 | 2.59 |
| 2007 | .73 | .47 | .79 | .75 | 2.74 |
| 2008 | .94 | .48 | **.88** | **.70** | **3.00** |
| 2009 | **.95** | **.50** | **.90** | **.75** | **3.10** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .345 | .365 | .365 | .365 | 1.44 |
| 2005 | .365 | .39 | .39 | .39 | 1.54 |
| 2006 | .39 | .42 | .42 | .42 | 1.65 |
| 2007 | .42 | .44 | .44 | .44 | 1.74 |
| 2008 | .44 | .46 | .46 | | |

**BUSINESS:** SCANA Corporation is a holding company for South Carolina Electric & Gas Company, which supplies electricity to 646,000 customers in South Carolina. Supplies gas and transmission service to 1.2 million customers in North and South Carolina and Georgia. Owns gas pipelines. Acquired PSNC Energy 2/00. Electric revenue breakdown, '07: residential, 41%; commercial, 31%; industrial, 17%; other, 11%. Generating sources, '07: coal, 61%; nuclear, 21%; oil & gas, 12%; hydro, 4%; purchased, 2%. Fuel costs: 62% of revenues. '07 reported deprec. rate: 3.1%. Has 5,700 employees. Chairman, President & CEO: William B. Timmerman. Inc.: South Carolina. Address: 1426 Main St., Columbia, SC 29201-2845. Tel.: 803-217-9000. Internet: www.scana.com.

**SCANA's South Carolina Electric & Gas subsidiary plans to build two nuclear units.** The company's 55% stake in the plant would add 1,229 megawatts of base-load capacity at a projected cost (including transmission associated with the project) of $6.3 billion. SCE&G has asked the NRC for a Construction and Operating License, which the utility expects to receive by late 2011. SCE&G has also asked the South Carolina regulators for permission to build the plant under the state's Base Load Review Act (BLRA). This Act will enable the utility to recover its construction costs as the units are being built. SCE&G estimates that this would result in base rate increases of 2.5% annually. The company expects a ruling from the state commission in February of 2009.

**Wall Street appears to be concerned about the construction risk that SCE&G would assume.** The provisions of the BLRA, along with federal incentives, would reduce the risk to the utility, but would not eliminate it. Moreover, any project of this size is a big undertaking for a mid-cap company. This stock has performed weakly since SCE&G made the BLRA filing in late May. As a result, its yield is now almost a full percentage point above the industry average.

**Earnings are likely to rise significantly this year.** SCE&G received a $76.9 million electric tariff hike at the start of 2008. Our profit estimate is within SCANA's targeted range of $2.90-$3.05 a share.

**Two gas rate filings are pending.** PSNC Energy has reached a settlement with the staff of the North Carolina commission (which must still approve the agreement) for a rate boost of $9.1 million (1.3%) based on a 10.6% return on a 51% common-equity ratio. SCE&G has filed for a $4.7 million (0.9%) increase under a state provision that allows it to request an increase whenever it is underearning its allowed ROE by half a percentage point. New tariffs in each state should be in place at the start of November. This should help lift SCANA's earnings in 2009.

**Investors who don't mind assuming some nuclear-related risk should find this stock's yield attractive.** Total return potential to 2011-2013 is a cut above average for a utility.

*Paul E. Debbas, CFA* *August 29, 2008*

(A) Excl. nonrec. gains (losses): '95, (16¢); '97, 16¢; '99, 29¢; '00, 28¢; '01, $3.00; '02, ($3.72); '03, 31¢; '04, (23¢); '05, 3¢; '06, 9¢. Next earnings report due late Oct. (B) Div'ds historically paid in early Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. intang. In '07: $8.00/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in SC: 11% electric in '08; 10.25% gas in '05; in '06 in NC: none specified; earned on avg. com. eq., '07: 11.0%. Regulatory Climate: Avg.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 50 |
| Earnings Predictability | 95 |

# SEMPRA ENERGY NYSE-SRE

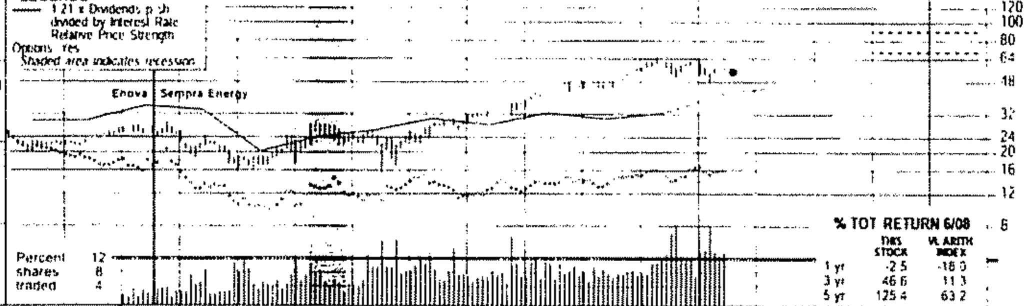
RECENT PRICE 54.65 | P/E RATIO 14.6 (Trailing: 12.7 / Median: 11.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 3 Raised 5/23/08
SAFETY 2 Lowered 2/4/00
TECHNICAL 3 Raised 8/8/08
BETA .95 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 27.1 | 29.3 | 26.0 | 24.9 | 28.6 | 26.3 | 30.9 | 37.9 | 47.9 | 57.3 | 66.4 | 63.0 |
| Low | 21.4 | 23.8 | 17.1 | 16.7 | 17.1 | 15.5 | 22.3 | 29.5 | 35.5 | 42.9 | 50.9 | 48.6 |

Target Price Range
2011 | 2012 | 2013

LEGENDS
1.21 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession




**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 90 | (+65%) | 15% |
| Low | 70 | (+30%) | 9% |

**Insider Decisions**

| | S | O | N | D | J | F | M | A | M |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 2 | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 1 |
| to Sell | 2 | 0 | 1 | 0 | 1 | 0 | 0 | 2 | 1 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 180 | 231 | 228 |
| to Sell | 192 | 157 | 194 |
| Hld's(000) | 172828 | 176105 | 174741 |

% TOT. RETURN 6/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -2.5 | -18.0 |
| 3 yr. | 46.6 | 11.3 |
| 5 yr. | 125.4 | 63.2 |

Sempra Energy was formed through the merger of Enova Corp. and Pacific Enterprises on June 26, 1998. Enova stockholders received one Sempra share for each Enova share, and Pacific Enterprises stockholders received 1.5038 Sempra shares for every Pacific Enterprises share.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 23.31 | 22.89 | 35.38 | 39.27 | 29.39 | 34.81 | 40.18 | 45.64 | 44.89 | 43.79 | 42.25 | 45.00 | Revenues per sh | 54.25 |
| 5.16 | 5.36 | 4.91 | 5.39 | 5.71 | 5.56 | 6.58 | 5.96 | 6.74 | 6.93 | 6.85 | 8.15 | "Cash Flow" per sh | 10.50 |
| 1.24 | 1.66 | 2.06 | 2.55 | 2.79 | 3.01 | 3.93 | 3.52 | 4.23 | 4.26 | 3.75 | 4.40 | Earnings per sh A | 5.75 |
| 1.56 | 1.56 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.16 | 1.20 | 1.24 | 1.37 | 1.60 | Div'd Decl'd per sh B ■ † | 2.00 |
| 1.85 | 2.48 | 3.76 | 5.22 | 5.92 | 4.63 | 4.62 | 5.46 | 7.28 | 7.70 | 8.55 | 11.15 | Cap'l Spending per sh | 9.75 |
| 12.29 | 12.58 | 12.35 | 13.17 | 13.79 | 17.17 | 20.78 | 23.95 | 28.66 | 31.87 | 32.80 | 33.70 | Book Value per sh C | 44.25 |
| 237.00 | 237.40 | 201.90 | 204.48 | 204.91 | 226.60 | 234.18 | 257.19 | 262.01 | 261.21 | 245.00 | 231.00 | Common Shs Outst'g D | 240.00 |
| 21.1 | 12.6 | 9.4 | 9.7 | 8.2 | 9.0 | 8.6 | 11.8 | 11.5 | 14.0 | Bold figures are | | Avg Ann'l P/E Ratio | 14.0 |
| 1.10 | .73 | .61 | .50 | .45 | .51 | .45 | .63 | .62 | .73 | Value Line | | Relative P/E Ratio | .90 |
| 6.0% | 7.4% | 5.2% | 4.1% | 4.4% | 3.7% | 2.9% | 2.8% | 2.5% | 2.1% | estimates | | Avg Ann'l Div'd Yield | 2.5% |
| 5525.0 | 5435.0 | 7143.0 | 8029.0 | 6020.0 | 7887.0 | 9410.0 | 11737 | 11761 | 11438 | 10350 | 10400 | Revenues ($mill) | 13000 |
| 306.0 | 405.0 | 440.0 | 534.0 | 586.0 | 655.0 | 930.0 | 898.0 | 1118.0 | 1135.0 | 955 | 1090 | Net Profit ($mill) | 1445 |
| 31.1% | 30.7% | 38.0% | 28.8% | 19.9% | 23.2% | 17.2% | | 31.3% | 33.6% | 37.0% | 37.5% | Income Tax Rate | 39.0% |
| 3.6% | 2.2% | 3.6% | 5.2% | 10.8% | 8.4% | 2.9% | 5.3% | 7.2% | 11.5% | 13.0% | 9.0% | AFUDC % to Net Profit | 7.0% |
| 47.3% | 47.6% | 56.2% | 55.7% | 58.6% | 48.4% | 45.3% | 43.1% | 37.0% | 34.8% | 37.5% | 41.0% | Long-Term Debt Ratio | 40.0% |
| 49.3% | 49.0% | 40.4% | 41.2% | 38.6% | 49.0% | 52.6% | 55.1% | 61.4% | 63.7% | 61.0% | 57.5% | Common Equity Ratio | 59.0% |
| 5912.0 | 6092.0 | 6166.0 | 6532.0 | 7312.0 | 7931.0 | 9255.0 | 11178 | 12229 | 13071 | 13100 | 13425 | Total Capital ($mill) | 18000 |
| 5441.0 | 5394.0 | 5726.0 | 6217.0 | 6832.0 | 10474 | 11086 | 12101 | 13175 | 14884 | 16250 | 18025 | Net Plant ($mill) | 21800 |
| 6.8% | 8.3% | 9.0% | 10.2% | 9.8% | 9.8% | 11.3% | 9.2% | 10.3% | 9.6% | 8.5% | 9.0% | Return on Total Cap'l | 9.0% |
| 9.8% | 12.7% | 16.3% | 18.4% | 19.3% | 16.0% | 18.4% | 14.1% | 14.5% | 13.3% | 11.5% | 13.5% | Return on Shr. Equity | 13.5% |
| 10.1% | 13.2% | 17.2% | 19.4% | 20.4% | 16.6% | 18.9% | 14.4% | 14.8% | 13.5% | 12.0% | 14.0% | Return on Com Equity E | 13.5% |
| NMF | 9% | 7.4% | 11.9% | 13.1% | 11.3% | 14.9% | 10.1% | 11.0% | 9.7% | 7.5% | 9.0% | Retained to Com Eq | 9.0% |
| 110% | 94% | 58% | 40% | 37% | 33% | 22% | 31% | 26% | 29% | 37% | 36% | All Div'ds to Net Prof | 34% |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $6242.0 mill. **Due in 5 Yrs** $3117.0 mill.
**LT Debt** $4589.0 mill. **LT Interest** $252.0 mill.
(LT interest earned: 7.3x)

**Leases, Uncapitalized** Annual rentals $120.0 mill.
**Pension Assets**-12/07 $2.53 bill. Oblig. $2.79 bill.

**Pfd Stock** $179.0 mill. **Pfd Div'd** $9.0 mill.
1,373,770 shs. 4.40%-5% cumulative, $20 par, callable $20.25-$24; 2,040,000 shs. $1.70-$1.82 cum., no par, callable $25.595-$26; 800,000 shs. $4.36-$4.75 cum., no par, callable $100-$101.50; 811,073 shs. 6% cum., $25 par.

**Common Stock** 250,341,668 shs.
**as of 4/30/08**
**MARKET CAP: $14 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | -.2 | +5.3 | +.2 |
| Avg. Indust. Use (MWH) | 4608 | 4596 | 4474 |
| Avg. Indust. Revs. per KWH (¢) | 6.58 | 8.00 | 10.06 |
| Capacity at Peak (Mw) | NMF | NMF | NMF |
| Peak Load, Summer (Mw) | NMF | NMF | NMF |
| Annual Load Factor (%) | NMF | NMF | NMF |
| % Change Customers (yr-end) | +1.5 | +1.3 | +.7 |
| Fixed Charge Cov. (%) | 274 | 409 | 419 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 10.0% | 5.0% | 3.5% |
| "Cash Flow" | 3.0% | 4.0% | 8.0% |
| Earnings | 7.0% | 10.0% | 6.0% |
| Dividends | -2.5% | 3.5% | 9.0% |
| Book Value | 7.5% | 16.5% | 8.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 2697 | 2276 | 2770 | 3994 | 11737 |
| 2006 | 3336 | 2486 | 2694 | 3245 | 11761 |
| 2007 | 3004 | 2661 | 2663 | 3110 | 11438 |
| 2008 | 3270 | 2180 | 2300 | 2600 | 10350 |
| 2009 | 2800 | 2300 | 2500 | 2800 | 10400 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .92 | .49 | .71 | 1.39 | 3.52 |
| 2006 | .90 | .71 | 1.29 | 1.33 | 4.23 |
| 2007 | .86 | 1.06 | 1.24 | 1.10 | 4.26 |
| 2008 | .92 | .78 | 1.05 | 1.00 | 3.75 |
| 2009 | 1.15 | .90 | 1.20 | 1.15 | 4.40 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .25 | .25 | .25 | .25 | 1.00 |
| 2005 | .25 | .29 | .29 | .29 | 1.12 |
| 2006 | .29 | .30 | .30 | .30 | 1.19 |
| 2007 | .30 | .31 | .31 | .31 | 1.23 |
| 2008 | .31 | .32 | .35 | | |

**BUSINESS:** Sempra Energy is a holding company for San Diego Gas & Electric Co., which sells electricity and gas mainly in San Diego County, & Southern California Gas Co., which distributes gas to most of Southern California. Customers: 1.4 million electric, 6.5 million gas. Has various nonutility subsidiaries (54% of '07 earnings). Electric revenue breakdown, '07: residential, 45%; commercial, 39%; industrial, 10%; other, 6%. Purchases most of its power; the rest is nuclear and gas. Power costs: 42% of revenues. '07 deprec. rate: 3.3%. Has 14,300 employees. Chairman & CEO: Donald E. Felsinger. President & COO: Neal E. Schmale. Inc.: California. Address: 101 Ash St., San Diego, California 92101-3017. Tel.: 619-696-2034. Internet: www.sempra.com.

**Sempra Energy's annual income from its commodities business should become more predictable thanks to its joint venture with Royal Bank of Scotland (RBS).** The joint venture agreement will split the profits in a manner that will give Sempra the majority, up to a specified level. Thus, earnings in the inherently unpredictable energy-marketing business should vacillate less from year to year. On the other hand, the company has sacrificed some of the upside potential of this business. Because profits from this operation will most likely be well below the $499 million posted in 2007, Sempra's earnings are likely to decline in 2008. Our estimate is at the midpoint of the company's guidance of $3.65-$3.85 a share.

**Earnings should improve in 2009.** Utility income ought to advance thanks to rate increases that Southern California Gas and San Diego Gas & Electric were awaiting as this report went to press. On the nonutility side, a few major projects have gone into service this year or will do so in the coming months, and these will benefit corporate profits in 2009. These include a 25% stake in a major gas pipeline project (in which Sempra's share will cost more than $1 billion) and two liquefied natural gas terminals. Finally, the reduction in shares outstanding will help boost share earnings.

**Sempra has agreed to acquire EnergySouth for $510 million in cash.** EnergySouth has 93,000 gas customers in Alabama, but its two large gas storage facilities provided the big attraction for Sempra. The deal requires the approval of EnergySouth's shareholders and various regulatory bodies and should be completed by the end of 2008. Sempra expects the deal to be "slightly accretive" to earnings in 2009 and to contribute as much as $0.30 a share in 2012. Our estimates and projections will not include EnergySouth until after the transaction has been completed.

**Sempra stock offers decent risk-adjusted total return potential for the 3- to 5-year period.** Over that time, the company has a lot of investment opportunities that should enable it to benefit from the rising nationwide demand for natural gas. This should produce strong earnings and dividend growth over that time.

*Paul E. Debbas, CFA* — *August 8, 2008*

(A) Diluted egs. Excl. nonrec. gain (loss): '05, 17¢; '06, (6¢); gain (losses) from disc. ops.: '04, (10¢); '05, (4¢); '06, $1.21; '07, (10¢). '05 EPS don't add due to rounding. Next egs. report due early Nov. (B) Div'ds historically paid mid-Jan., Apr., July, & Oct. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $3.56/sh. (D) In mill. Excl. ESOP shs. (E) Rate base: Net orig. cost. Rate all'd on com. eq.: SDG&E in '08, 11.1%; SoCalGas in '03, 10.82%; earned on avg. com. eq., '07: 14.2%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 90 |

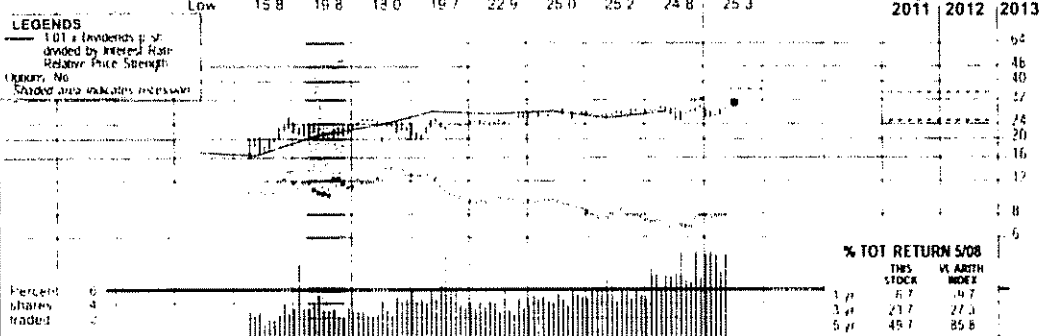
# VECTREN CORP. NYSE-VVC

RECENT PRICE 30.92 | P/E RATIO 16.7 (Trailing: 17.3 Median: NMF) | RELATIVE P/E RATIO 1.02 | DIV'D YLD 4.3% | VALUE LINE

TIMELINESS 3 Lowered 5/9/08
SAFETY 2 Lowered 1/5/07
TECHNICAL 4 Lowered 6/20/08
BETA .90 (1.00 = Market)

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| High | 26.5 | 24.4 | 26.1 | 20.1 | 27.1 | 29.5 | 29.3 | 30.5 | 31.0 |
| Low | 15.8 | 19.8 | 18.0 | 19.7 | 22.9 | 25.0 | 25.2 | 24.8 | 25.3 |

Target Price Range 2011 | 2012 | 2013




**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 35 | (+15%) | 7% |
| Low | 25 | (-20%) | Nil |

**Insider Decisions**

| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 3 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 2 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 79 | 112 | 99 |
| to Sell | 104 | 74 | 98 |
| Hld's(000) | 43375 | 45478 | 42866 |

**% TOT. RETURN 5/08**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 6.7 | 4.7 |
| 3 yr. | 21.7 | 27.3 |
| 5 yr. | 49.7 | 85.8 |

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren. Data prior to the merger are pro forma.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 16.88 | 26.84 | 32.05 | 26.53 | 21.00 | 22.26 | 26.62 | 26.83 | 29.88 | 30.85 | 33.75 | Revenues per sh | 42.30 |
| | 2.87 | 2.86 | 2.89 | 3.43 | 3.17 | 3.27 | 3.87 | 3.69 | 4.29 | 4.20 | 4.50 | "Cash Flow" per sh | 5.05 |
| | 1.48 | 1.17 | 1.08 | 1.68 | 1.56 | 1.42 | 1.81 | 1.44 | 1.83 | 1.85 | 1.95 | Earnings per sh A | 2.05 |
| | .95 | .98 | 1.03 | 1.07 | 1.11 | 1.15 | 1.19 | 1.23 | 1.27 | 1.31 | 1.35 | Div'd Decl'd per sh B■† | 1.47 |
| | | 2.67 | 3.48 | 3.22 | 3.12 | 3.66 | 3.04 | 3.70 | 4.38 | 3.85 | 3.45 | Cap'l Spending per sh | 3.65 |
| | 11.55 | 11.91 | 12.53 | 12.79 | 14.18 | 14.42 | 15.01 | 15.43 | 16.16 | 17.45 | 18.00 | Book Value per sh C | 19.30 |
| | 61.47 | 61.42 | 67.70 | 68.01 | 75.60 | 75.90 | 76.19 | 76.10 | 76.36 | 81.00 | 81.20 | Common Shs Outst'g D | 81.80 |
| | | 17.4 | 20.3 | 14.2 | 14.8 | 17.6 | 15.1 | 18.9 | 15.3 | Bold figures are | | Avg Ann'l P/E Ratio | 14.5 |
| | | 1.13 | 1.04 | .78 | .84 | .93 | .80 | 1.02 | .80 | Value Line | | Relative P/E Ratio | .95 |
| | | 4.8% | 4.7% | 4.5% | 4.8% | 4.6% | 4.4% | 4.5% | 4.5% | estimates | | Avg Ann'l Div'd Yield | 4.9% |
| | 1037.4 | 1648.7 | 2170.0 | 1804.3 | 1587.6 | 1689.8 | 2028.0 | 2041.6 | 2281.9 | 2500 | 2740 | Revenues ($mill) | 3460 |
| | 90.6 | 72.0 | 73.1 | 114.0 | 111.2 | 108.0 | 136.8 | 108.8 | 143.1 | 145 | 160 | Net Profit ($mill) | 170 |
| | 33.6% | 32.2% | 20.3% | 25.4% | 25.3% | 26.5% | 24.4% | 21.8% | 34.7% | 35.0% | 35.0% | Income Tax Rate | 35.0% |
| | | | 7.7% | 4.6% | 4.5% | 3.0% | 1.4% | 3.8% | 2.8% | 3.0% | 3.0% | AFUDC % to Net Profit | 3.0% |
| | 40.0% | 45.8% | 54.4% | 52.3% | 50.0% | 48.1% | 51.2% | 50.7% | 50.2% | 49.0% | 49.5% | Long-Term Debt Ratio | 50.0% |
| | 58.4% | 53.0% | 45.5% | 47.7% | 50.0% | 51.8% | 48.8% | 49.3% | 49.8% | 51.0% | 50.5% | Common Equity Ratio | 50.0% |
| | 1215.8 | 1380.6 | 1863.1 | 1824.4 | 2144.7 | 2111.5 | 2341.3 | 2382.2 | 2479.1 | 2785 | 2880 | Total Capital ($mill) | 3150 |
| | 1336.3 | 1555.8 | 1595.0 | 1646.1 | 2003.7 | 2156.2 | 2251.9 | 2385.5 | 2539.7 | 2655 | 2725 | Net Plant ($mill) | 2925 |
| | 8.6% | 6.1% | 5.5% | 7.7% | 6.6% | 6.4% | 7.2% | 6.0% | 7.2% | 6.5% | 7.0% | Return on Total Cap'l | 6.5% |
| | 12.5% | 9.6% | 8.6% | 13.1% | 10.4% | 9.9% | 12.0% | 9.3% | 11.6% | 10.0% | 11.0% | Return on Shr. Equity | 10.5% |
| | 12.6% | 9.7% | 8.5% | 13.1% | 10.4% | 9.9% | 12.0% | 9.3% | 11.6% | 10.0% | 11.0% | Return on Com Equity E | 10.5% |
| | 4.8% | 1.5% | 3% | 4.8% | 3.0% | 1.9% | 4.0% | 1.3% | 3.8% | 3.0% | 3.5% | Retained to Com Eq | 3.0% |
| | 63% | 85% | 96% | 63% | 71% | 81% | 66% | 86% | 67% | 71% | 69% | All Div'ds to Net Prof | 72% |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt** $1634.5 mill. **Due in 5 Yrs** $45.9 mill.
**LT Debt** $1329.1 mill. **LT Interest** $72.2 mill.
(LT interest earned: 4.0x)

**Pension Assets-12/07** $211.8 mill. **Oblig.** $249.6 mill.

**Pfd Stock** None

**Common Stock** 76,357,338 shs. **as of 4/30/08**
**MARKET CAP. $2.4 billion (Mid Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.5 | -3.1 | +3.5 |
| Avg. Indust. Use (MWH) | 24074 | 23800 | 23289 |
| Avg. Indust. Revs. per KWH (¢) | 4.64 | 4.99 | 5.50 |
| Capacity at Peak (Mw) | 1534 | 1517 | 1487 |
| Peak Load, Summer (Mw) | 1291 | 1300 | 1341 |
| Annual Load Factor (%) | 61.2 | 56.3 | 60.6 |
| % Change Customers (yr-end) | +.6 | +1.1 | +.9 |
| Fixed Charge Cov. (%) | 252 | 226 | 254 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | -- | -.5% | 7.5% |
| "Cash Flow" | -- | 5.0% | 4.0% |
| Earnings | -- | 5.5% | 3.5% |
| Dividends | -- | 3.5% | 3.0% |
| Book Value | -- | 4.5% | 3.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 677.2 | 326.2 | 310.8 | 713.8 | 2028.0 |
| 2006 | 774.5 | 317.5 | 340.5 | 609.1 | 2041.6 |
| 2007 | 834.0 | 421.7 | 381.4 | 644.8 | 2281.9 |
| 2008 | 902.1 | 470 | 420 | 707.9 | 2500 |
| 2009 | 960 | 530 | 480 | 770 | 2740 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .74 | .18 | .22 | .67 | 1.81 |
| 2006 | .76 | .06 | .16 | .46 | 1.44 |
| 2007 | .88 | .21 | .22 | .52 | 1.83 |
| 2008 | .84 | .20 | .20 | .61 | 1.85 |
| 2009 | .90 | .20 | .20 | .65 | 1.95 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■† Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .285 | .285 | .285 | .295 | 1.15 |
| 2005 | .295 | .295 | .295 | .305 | 1.19 |
| 2006 | .305 | .305 | .305 | .315 | 1.23 |
| 2007 | .315 | .315 | .315 | .325 | 1.27 |
| 2008 | .325 | .325 | | | |

**BUSINESS:** Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base of 1,140,000. 2007 Elect. (gas) revs: resid., 36% (67%); commer., 25% (27%); indust., 31% (6%); other, 8% (Nil). Revenue sources: Elect., 18%; Gas, 82%. Fuel costs: elect., 36%; gas, 69%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 10 years. '07 deprec. rate: 3.6%. Has 3,579 employees. Chairman & CEO: Niel C. Ellerbrook. President: Carl Chapman. Inc.: IN. Address: 20 Northwest 4th St., Evansville, Indiana 47741. Tel.: 812-465-5300. Internet: www.vectren.com.

**Vectren is adding to its generating portfolio.** VVC must not only replace the 100-megawatt (mw) purchase-power contract that expires in 2010, but must increase its 10% reserve margin to the 15% required by regulators. For starters, it bought the 30-mw output of a wind farm for 20 years. In 2007, it exited from a 20% stake in a 630-megawatt (mw) coal gasification plant because of the high cost. In its place, it planned to build a 100-mw, $80 million natural gas-fired peaking unit. This project, too, was scrapped in favor of a less-risky three-year 100-mw purchase-power agreement starting in 2010. The new facilities, coupled with VVC's conservation program, should satisfy capacity needs for another few years.

**Profits of the unregulated businesses might be down a bit this year.** VVC owns two low-sulfur coal mines with reserves of 34 million tons. The mines not only supply company plants with three million tons a year, but sell one million tons annually in the open market. Too, Vectren owns mineral rights, but not the land, to another 81 million tons that will start production next year. Though mine operations incurred a small loss in the first quarter of 2008 due to the cost of securing a roof structure, they should turn profitable for the balance of the year. VVC also has a 61% stake in ProLiance Energy, which trades and markets natural gas. Results here are being hurt by this year's reduced natural gas price volatility.

**Earnings may show little progress in 2008.** The utility sector will benefit from base rate increases in the second half of 2007, ongoing recovery of environmental costs, and wider margins on energy sales. But these pluses will be largely offset by reduced contributions from the nonutility enterprises. On balance, we estimate near-flat earnings this year. Higher rates in Ohio on a filing for $27 million and likely improvement in noncore operations suggest a better performance in 2009.

**Utility investors might consider these good-quality shares.** The yield is a cut above the industry norm, and based on our projection of earnings gains after this year to 2011-2013, dividend growth prospects over the same time frame are in line with those of the group.

*Arthur H. Medalie* *June 27, 2008*

(A) Diluted EPS. Next earnings report due late July. Excl. nonrecur. gain (losses): '00, 8¢; '01, (13¢); '03, (6¢). Incl. charges for merger costs: '00, 60¢; '01, 17¢. (B) Div'ds historically paid in early March, early June, early September, and early December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. in '07: $5.42/sh. (D) In millions. (E) Elec. inc. rate base determination: fair value. Rate allowed on elect. common equity in '95: 12.25%. Earned on avg. com. eq. '07: 11.5%. Regulatory Climate: Above Average.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 35 |
| Earnings Predictability | 75 |

# WISCONSIN ENERGY NYSE-WEC

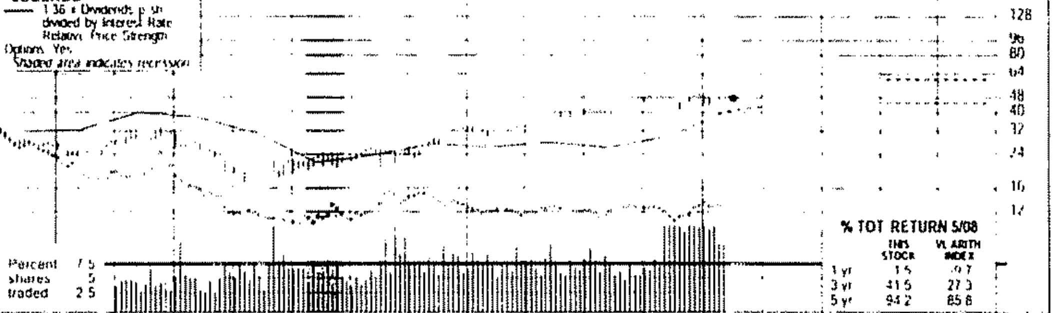
RECENT PRICE 47.73 | P/E RATIO 17.0 (Trailing 15.8 / Median 15.0) | RELATIVE P/E RATIO 1.04 | DIV'D YLD 2.4% | VALUE LINE

TIMELINESS 3 Raised 11/9/07
SAFETY 2 Lowered 7/11/97
TECHNICAL 3 Lowered 5/30/08
BETA .80 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 29.1 | 34.0 | 31.6 | 23.6 | 24.6 | 26.5 | 33.7 | 34.6 | 40.8 | 48.7 | 50.5 | 49.6 |
| Low | 23.0 | 27.0 | 19.1 | 16.8 | 19.1 | 20.2 | 22.6 | 29.5 | 33.3 | 38.2 | 41.1 | 42.0 |

Target Price Range 2011 2012 2013

LEGENDS
—— 1.36 x Dividends p sh divided by Interest Rate
Relative Price Strength
Options: Yes
Shaded area indicates recession




### 2011-13 PROJECTIONS

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+25%) | 8% |
| Low | 45 | (-5%) | 2% |

### Insider Decisions

| | A | S | O | N | D | J | F | M | A |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 1 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 1 | 0 | 1 | 0 | 1 | 1 | 0 | 0 |
| to Sell | 0 | 1 | 1 | 1 | 0 | 1 | 1 | 0 | 0 |

### Institutional Decisions

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 116 | 134 | 121 |
| to Sell | 125 | 118 | 117 |
| Hld's(000) | 76561 | 80075 | 81614 |

% TOT. RETURN 5/08

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr | 1.5 | -0.7 |
| 3 yr | 41.5 | 27.3 |
| 5 yr | 94.2 | 85.8 |

| 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 15.05 | 15.61 | 15.99 | 15.98 | 15.88 | 15.86 | 17.13 | 19.11 | 28.28 | 34.04 | 32.20 | 34.24 | 29.33 | 32.62 | 34.17 | 36.24 | **38.90** | **41.45** | Revenues per sh | **49.50** |
| 3.22 | 3.84 | 3.81 | 4.28 | 4.25 | 2.96 | 4.13 | 4.53 | 4.48 | 5.44 | 5.68 | 5.71 | 5.16 | 5.78 | 5.80 | 5.97 | **5.90** | **6.60** | "Cash Flow" per sh | **8.50** |
| 1.67 | 1.81 | 1.67 | 2.13 | 1.97 | .54 | 1.65 | 1.88 | 1.08 | 1.34 | 2.37 | 2.26 | 1.55 | 2.56 | 2.64 | 2.84 | **2.80** | **3.25** | Earnings per sh A | **4.25** |
| 1.29 | 1.34 | 1.40 | 1.46 | 1.51 | 1.54 | 1.56 | 1.56 | 1.37 | .80 | .80 | .80 | .83 | .88 | .92 | 1.00 | **1.08** | **1.24** | Div'd Decl'd per sh B ■ † | **1.60** |
| 3.11 | 3.43 | 2.76 | 2.50 | 3.53 | 3.13 | 3.52 | 4.44 | 5.29 | 6.03 | 5.07 | 5.89 | 5.70 | 6.79 | 8.35 | 10.56 | **10.45** | **7.20** | Cap'l Spending per sh | **7.25** |
| 14.97 | 15.67 | 16.01 | 16.89 | 17.42 | 16.51 | 16.46 | 16.89 | 17.00 | 17.81 | 18.44 | 19.92 | 21.31 | 22.91 | 24.70 | 26.50 | **27.95** | **29.65** | Book Value per sh C | **36.00** |
| 103.09 | 105.32 | 108.94 | 110.82 | 111.68 | 112.87 | 115.61 | 118.90 | 118.65 | 115.42 | 116.03 | 118.43 | 116.99 | 116.98 | 116.97 | 116.94 | **117.00** | **117.00** | Common Shs Outst'g D | **117.00** |
| 15.6 | 15.2 | 15.2 | 13.1 | 14.3 | 47.3 | 18.0 | 13.3 | 18.7 | 12.1 | 10.5 | 12.4 | 17.5 | 14.5 | 16.0 | 16.5 | Bold figures are | | Avg Ann'l P/E Ratio | **12.5** |
| .95 | .90 | 1.00 | .88 | .90 | 2.73 | .94 | .76 | 1.22 | .62 | .57 | .71 | .92 | .77 | .86 | .87 | Value Line | | Relative P/E Ratio | **.85** |
| 5.0% | 4.9% | 5.5% | 5.2% | 5.4% | 6.0% | 5.2% | 6.3% | 6.8% | 3.6% | 3.3% | 2.8% | 2.6% | 2.4% | 2.2% | 2.1% | estimates | | Avg Ann'l Div'd Yield | **3.0%** |

**CAPITAL STRUCTURE as of 3/31/08**
Total Debt $4383.8 mill. Due in 5 Yrs $1949.9 mill.
LT Debt $2974.2 mill. LT Interest $178.5 mill.
Incl. $154.1 mill. capitalized leases.
(LT interest earned: 3.3x)
**Leases, Uncapitalized** Annual rentals $37.0 mill.

**Pension Assets-12/07** $1.01 bill. **Oblig.** $1.16 bill.
**Pfd Stock** $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101;
44,498 shs. 6%, $100 par.
**Common Stock** 116,927,953 shs.

**MARKET CAP: $5.6 billion (Large Cap)**

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1980.0 | 2272.6 | 3354.7 | 3928.5 | 3736.2 | 4054.3 | 3431.1 | 3815.5 | 3996.4 | 4237.8 | **4550** | **4850** | Revenues ($mill) | **5800** |
| 189.3 | 231.5 | 132.0 | 218.8 | 270.8 | 269.2 | 221.2 | 304.6 | 313.7 | 337.7 | **335** | **385** | Net Profit ($mill) | **500** |
| 32.7% | 33.8% | 43.7% | 40.9% | 37.4% | 35.5% | 37.5% | 32.9% | 35.8% | 39.1% | **39.0%** | **39.0%** | Income Tax Rate | **39.0%** |
| 5.7% | 5.6% | 12.3% | 6.9% | 4.1% | 6.9% | 10.0% | 12.5% | 19.0% | 23.8% | **15.0%** | **13.0%** | AFUDC % to Net Profit | **8.0%** |
| 47.5% | 48.8% | 58.9% | 62.2% | 59.8% | 59.9% | 56.2% | 52.8% | 51.3% | 50.3% | **51.5%** | **51.5%** | Long-Term Debt Ratio | **48.5%** |
| 51.7% | 45.9% | 40.5% | 37.2% | 39.6% | 39.6% | 43.3% | 46.7% | 48.2% | 49.2% | **48.0%** | **48.0%** | Common Equity Ratio | **51.0%** |
| 3682.6 | 4372.8 | 4979.9 | 5523.8 | 5400.3 | 5963.3 | 5762.3 | 5741.5 | 5992.6 | 6302.1 | **6825** | **7225** | Total Capital ($mill) | **8275** |
| 3238.4 | 3846.6 | 4152.4 | 4188.0 | 4398.8 | 5926.1 | 5903.1 | 6362.9 | 7052.5 | 7681.2 | **8545** | **9000** | Net Plant ($mill) | **10225** |
| 6.6% | 6.7% | 4.7% | 5.8% | 7.1% | 6.3% | 5.6% | 7.0% | 6.6% | 7.0% | **6.5%** | **7.0%** | Return on Total Cap'l | **7.5%** |
| 9.8% | 10.3% | 6.4% | 10.5% | 12.5% | 11.3% | 8.8% | 11.2% | 10.7% | 10.8% | **10.0%** | **11.0%** | Return on Shr. Equity | **12.0%** |
| 9.9% | 10.9% | 6.5% | 10.6% | 12.6% | 11.4% | 8.8% | 11.3% | 10.8% | 10.9% | **10.0%** | **11.0%** | Return on Com Equity E | **12.0%** |
| 6% | 1.9% | NMF | 6.0% | 8.3% | 7.4% | 4.9% | 7.5% | 7.1% | 7.1% | **6.5%** | **7.0%** | Retained to Com Eq | **7.5%** |
| 94% | 84% | NMF | 43% | 35% | 35% | 45% | 34% | 35% | 35% | **38%** | **38%** | All Div'ds to Net Prof | **37%** |

### ELECTRIC OPERATING STATISTICS

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.8 | -4.0 | +2.2 |
| Avg. Indust. Use (MWH) | 16578 | NA | NA |
| Avg. Indust. Revs. per KWH (¢) | 5.15 | 5.80 | 6.02 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 6344 | 6376 | NA |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +1.0 | +.9 | +.2 |
| Fixed Charge Cov. (%) | 277 | 260 | 258 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 8.0% | 1.5% | 6.5% |
| "Cash Flow" | 4.5% | 2.5% | 6.5% |
| Earnings | 5.5% | 9.0% | 8.0% |
| Dividends | -4.5% | -1.0% | 9.5% |
| Book Value | 4.0% | 7.0% | 6.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 1094.7 | 788.5 | 797.3 | 1135.0 | 3815.5 |
| 2006 | 1247.0 | 814.4 | 839.8 | 1095.2 | 3996.4 |
| 2007 | 1301.1 | 906.5 | 881.5 | 1148.7 | 4237.8 |
| 2008 | 1431.8 | **950** | **950** | **1218.2** | **4550** |
| 2009 | **1525** | **1000** | **1025** | **1300** | **4850** |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .76 | .48 | .56 | .77 | 2.56 |
| 2006 | .88 | .50 | .60 | .65 | 2.64 |
| 2007 | .85 | .49 | .70 | .80 | 2.84 |
| 2008 | 1.04 | **.46** | **.50** | **.80** | **2.80** |
| 2009 | **1.10** | **.55** | **.65** | **.95** | **3.25** |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ † Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .20 | .21 | .21 | .21 | .83 |
| 2005 | .22 | .22 | .22 | .22 | .88 |
| 2006 | .23 | .23 | .23 | .23 | .92 |
| 2007 | .25 | .25 | .25 | .25 | 1.00 |
| 2008 | .27 | .27 | | | |

**BUSINESS:** Wisconsin Energy Corporation (WEC) is a holding company for We Energies, which provides electric, gas & steam service in WI & upper MI. Customers: 1.1 mill. elec., 1 mill. gas. Acq'd Edison Sault Electric 5/98; WICOR 4/00. Discontinued pump-manufacturing ops. in '04. Sold Point Beach nuclear plant in '07. Electric rev. breakdown, '07: residential, 34%; small commercial & industrial, 32%; large comm'l & ind'l, 25%; other, 9%. Generating sources, '07: coal, 54%; nuclear, 17%; gas, 6%; hydro, 1%; purch., 22%. Fuel costs: 48% of revs. '07 reported depr. rate (utility): 3.7%. Has 5,000 empls. Chairman, Pres. & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 2949, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

**Wisconsin Energy has received some good news concerning the coal-fired units it is building under its "Power the Future" program.** Under the program, the company is building two gas-fired and two coal-fired units that a non-utility subsidiary will own and lease to its utility sibling. Following yet another legal challenge against the coal plants, the company received a draft modified permit for the pollutant discharge elimination system it is installing. The final permit is expected this summer. This wouldn't preclude further litigation against the coal units, however.

**Two projects began commercial operation in the second quarter.** The second of the two gas-fired units is now running. This is benefiting Wisconsin Energy's earnings because the aforementioned lease is designed to produce a very healthy 12.7% return on equity. (Assuming that the first coal-fired unit enters commercial operation on schedule in September of 2009, this will boost the company's earning power even more.) Separately, a wind project was completed. This is a traditional utility investment, and as such was placed in the rate base via a general rate order that took effect earlier this year.

**Rising fuel costs are a problem.** Unlike in most states, the fuel-adjustment mechanism in Wisconsin is cumbersome and does not allow utilities to defer unrecovered fuel and purchased-power costs. Thus, utilities have some exposure when fuel costs are rising, as they are now. Despite the fact that the commission granted the utility an interim rate hike of $76.9 million to recoup higher fuel costs, Wisconsin Energy estimated in late April that it would swallow $20 million-$40 million of these expenses in 2008—and prices have become even higher since then. Accordingly, we have not raised our 2008 share-earnings estimate, which is at the low end of management's targeted range of $2.80-$2.90, despite the fact that March-period profits exceeded our estimate.

**We continue to think that this stock is overvalued.** Its yield is not only well below average for a utility, it's barely above the median for all dividend-paying stocks under our coverage. Total return potential to 2011-2013 is unimpressive, too.

*Paul E. Debbas, CFA* *June 27, 2008*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (9¢); '00, 19¢ net; '01, 1¢ net; '02, (88¢); '03, (20¢) net; '04, (81¢); gains on disc. ops.: '04, $1.54; '05, 4¢; '06, 4¢. '05 & '06 earnings don't add due to rounding. Next earnings report due early Aug. (B) Div'ds historically paid in early Mar., June, Sept., Dec. ■ Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '07: $12.00/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in '08: 10.75%; earned on avg. com. eq., '07: 11.1%. Regulat. Climate: Above Avg.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 75 |
| Earnings Predictability | 75 |

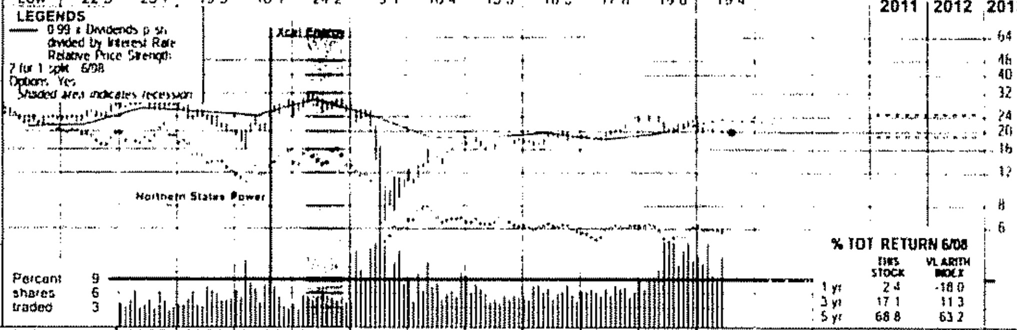
# XCEL ENERGY NYSE-XEL

RECENT PRICE 19.89 | P/E RATIO 13.3 (Trailing 13.3 / Median 15.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Lowered 1/16/07
SAFETY 2 Raised 5/14/04
TECHNICAL 3 Raised 8/8/08
BETA .80 (1.00 = Market)

| | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| High | 29.4 | 30.8 | 27.9 | 30.0 | 31.8 | 28.5 | 17.4 | 18.8 | 20.2 | 23.6 | 25.0 | 22.9 |
| Low | 22.3 | 25.7 | 19.3 | 16.1 | 24.2 | 5.1 | 10.4 | 15.5 | 16.5 | 17.8 | 19.6 | 19.4 |

Target Price Range 2011 2012 2013




% TOT. RETURN 6/08

| | THIS STOCK | VL ARITH INDEX |
|---|---|---|
| 1 yr | 2.4 | -18.0 |
| 3 yr | 17.1 | 11.3 |
| 5 yr | 68.8 | 63.2 |

**2011-13 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 25 | (+25%) | 10% |
| Low | 19 | (-5%) | 4% |

**Insider Decisions**

| | S | O | N | D | J | F | M | A | M |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 3Q2007 | 4Q2007 | 1Q2008 |
|---|---|---|---|
| to Buy | 160 | 197 | 167 |
| to Sell | 179 | 157 | 175 |
| Hld's(000) | 269962 | 265057 | 254808 |

Xcel Energy was formed through the merger of Northern States Power and New Century Energies on August 21, 2000. NSP stockholders received one share of Xcel for every NSP share, and NCE stockholders received 1.55 shares of Xcel for each NCE share. Data prior to 2000 reflect NSP on a stand-alone basis and are not comparable with Xcel data.

| 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | © VALUE LINE PUB., INC. | 11-13 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18.46 | 18.42 | 34.11 | 43.56 | 23.89 | 19.90 | 20.84 | 23.86 | 24.16 | 23.40 | 25.60 | 26.60 | Revenues per sh | 31.00 |
| 4.30 | 4.13 | 4.12 | 5.09 | 3.14 | 3.35 | 3.27 | 3.28 | 3.61 | 3.45 | 3.75 | 3.90 | "Cash Flow" per sh | 4.75 |
| 1.84 | 1.43 | 1.60 | 2.27 | .42 | 1.23 | 1.27 | 1.20 | 1.35 | 1.35 | 1.50 | 1.55 | Earnings per sh A | 2.00 |
| 1.43 | 1.45 | 1.48 | 1.50 | 1.13 | .75 | .81 | .85 | .88 | .91 | .94 | .97 | Div'd Decl'd per sh B ■ | 1.06 |
| 2.99 | 13.67 | 3.63 | 7.40 | 6.04 | 2.49 | 3.19 | 3.25 | 4.00 | 4.89 | 4.90 | 3.70 | Cap'l Spending per sh | 4.75 |
| 16.25 | 16.42 | 16.37 | 17.95 | 11.70 | 12.95 | 12.99 | 13.37 | 14.28 | 14.70 | 15.25 | 15.90 | Book Value per sh C | 18.50 |
| 152.70 | 155.73 | 339.79 | 345.02 | 398.71 | 398.96 | 400.46 | 403.39 | 407.30 | 428.78 | 430.00 | 432.00 | Common Shs Outst'g D | 438.00 |
| 15.2 | 16.6 | 14.3 | 12.4 | 40.8 | 11.6 | 13.6 | 15.4 | 14.8 | 16.7 | Bold figures are Value Line estimates | | Avg Ann'l P/E Ratio | 11.5 |
| .79 | .95 | .93 | .64 | 2.23 | .66 | .72 | .82 | .80 | .88 | | | Relative P/E Ratio | .75 |
| 5.1% | 6.1% | 6.4% | 5.3% | 6.6% | 5.2% | 4.7% | 4.6% | 4.4% | 4.0% | | | Avg Ann'l Div'd Yield | 4.8% |
| 2819.2 | 2869.0 | 11592 | 15028 | 9524.4 | 7937.5 | 8345.3 | 9625.5 | 9840.3 | 10034 | 11000 | 11500 | Revenues ($mill) | 13600 |
| 298.1 | 240.1 | 545.8 | 784.7 | 177.6 | 510.0 | 526.9 | 499.0 | 568.7 | 575.9 | 660 | 680 | Net Profit ($mill) | 890 |
| 26.0% | 21.6% | 35.8% | 28.2% | 32.7% | 23.7% | 23.2% | 25.8% | 24.2% | 33.8% | 33.5% | 33.5% | Income Tax Rate | 33.5% |
| 5.3% | 2.5% | 4.4% | 7.1% | 46.7% | 8.9% | 10.9% | 8.5% | 9.8% | 12.5% | 16.0% | 11.0% | AFUDC % to Net Profit | 12.0% |
| 39.9% | 54.7% | 58.8% | 66.7% | 59.6% | 55.3% | 55.0% | 51.7% | 52.1% | 49.7% | 52.5% | 52.0% | Long-Term Debt Ratio | 51.0% |
| 53.5% | 40.5% | 40.5% | 32.6% | 39.5% | 43.8% | 44.1% | 47.3% | 47.0% | 49.4% | 46.5% | 47.5% | Common Equity Ratio | 48.0% |
| 4637.7 | 6316.2 | 13745 | 18911 | 11815 | 11790 | 11801 | 11398 | 12371 | 12748 | 14100 | 14525 | Total Capital ($mill) | 16700 |
| 4395.2 | 4451.5 | 15273 | 21165 | 18816 | 13667 | 14096 | 14696 | 15549 | 16676 | 17825 | 18425 | Net Plant ($mill) | 20900 |
| 8.1% | 5.4% | 6.0% | 6.0% | 5.4% | 6.1% | 6.2% | 6.2% | 6.2% | 6.3% | 6.5% | 6.5% | Return on Total Cap'l | 7.0% |
| 10.7% | 8.4% | 9.6% | 12.5% | 3.7% | 9.7% | 9.9% | 9.1% | 9.6% | 9.0% | 10.0% | 10.0% | Return on Shr. Equity | 11.0% |
| 11.2% | 8.6% | 9.7% | 12.6% | 3.7% | 9.8% | 10.0% | 9.2% | 9.7% | 9.1% | 10.0% | 10.0% | Return on Com Equity E | 11.0% |
| 2.5% | NMF | 9% | 4.3% | NMF | 3.9% | 3.9% | 2.9% | 3.6% | 3.1% | 4.0% | 4.0% | Retained to Com Eq | 5.0% |
| 79% | 100% | 91% | 66% | NMF | 60% | 62% | 69% | 63% | 66% | 62% | 62% | All Div'ds to Net Prof | 53% |

**CAPITAL STRUCTURE as of 3/31/08**
**Total Debt $8259.3 mill Due in 5 Yrs $3336.5 mill**
**LT Debt $7139.8 mill LT Interest $464.1 mill**
Incl. 8,000,000 shares 7.875% tax-deductible Trust Originated Preferred Securities, liquidation value $25/share; 7,760,000 shares 7.60% cumulative, $25 par; $100 mill. 7.85% tax-deductible Trust Preferred Securities.
(LT interest earned: 2.9x)
**Leases, Uncapitalized** Annual rentals $104.6 mill.
**Pension Assets-12/07** $3.19 bill. **Oblig.** $2.66 bill.
**Pfd Stock** $105.0 mill. **Pfd Div'd** $4.2 mill.
1,049,800 shares $3.60 to $4.56 cumulative, $100 par, callable $102.00 to $103.75.
**Common Stock** 430,857,162 shs. **as of 4/25/08**
**MARKET CAP: $8.6 billion (Large Cap)**

**ELECTRIC OPERATING STATISTICS**

| | 2005 | 2006 | 2007 |
|---|---|---|---|
| % Change Retail Sales (KWH) | +3.6 | +1.8 | +2.0 |
| Avg. C & I Use (MWH) | 150 | 153 | 153 |
| Avg. C & I Revs. per KWH (¢) | 6.22 | 6.55 | 6.57 |
| Capacity at Peak (Mw) | NA | NA | NA |
| Peak Load, Summer (Mw) | 20854 | 21255 | 21108 |
| Annual Load Factor (%) | NA | NA | NA |
| % Change Customers (yr-end) | +.4 | +1.2 | +.9 |
| Fixed Charge Cov. (%) | 232 | 238 | 256 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '05-'07 to '11-'13 |
|---|---|---|---|
| Revenues | 2.5% | -7.0% | 4.5% |
| "Cash Flow" | -2.0% | -3.5% | 5.5% |
| Earnings | -3.5% | -2.0% | 7.5% |
| Dividends | -4.5% | -8.5% | 3.0% |
| Book Value | -1.0% | -1.5% | 4.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | 2381 | 2074 | 2289 | 2882 | 9625.5 |
| 2006 | 2888 | 2074 | 2411 | 2467 | 9840.3 |
| 2007 | 2764 | 2267 | 2400 | 2603 | 10034 |
| 2008 | 3028 | 2616 | 2700 | 2656 | 11000 |
| 2009 | 3000 | 2750 | 2900 | 2850 | 11500 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .31 | .18 | .47 | .24 | 1.20 |
| 2006 | .36 | .24 | .53 | .23 | 1.35 |
| 2007 | .28 | .16 | .59 | .31 | 1.35 |
| 2008 | .35 | .24 | .60 | .31 | 1.50 |
| 2009 | .33 | .28 | .62 | .32 | 1.55 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2004 | .188 | .188 | .208 | .208 | .79 |
| 2005 | .208 | .208 | .215 | .215 | .85 |
| 2006 | .215 | .215 | .223 | .223 | .88 |
| 2007 | .223 | .223 | .23 | .23 | .91 |
| 2008 | .23 | .23 | .238 | | |

**BUSINESS:** Xcel Energy Inc. is the parent of Northern States Power, which supplies power to Minnesota, Wisconsin, North Dakota, South Dakota, Michigan, & gas to Minnesota, Wisconsin, North Dakota & Michigan; Public Service of Colorado, which supplies power & gas to Colorado; & Southwestern Public Service, which supplies power to Texas & New Mexico. Customers: 3.3 mill. elec., 1.8 mill. gas. Electric revenue breakdown, '07: residential, 29%; commercial & industrial, 52%; other, 19%. Generating sources not available. Fuel costs: 57% of revs. '07 reported deprec. rate: 3.2%. Has 10,900 employees. Chairman, President & CEO: Richard C. Kelly. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Internet: www.xcelenergy.com.

**One of Xcel Energy's subsidiaries has filed a rate case.** Southwestern Public Service (SPS) is asking the Texas commission for a tariff hike of $94.4 million (9.1%) based on a return of 11.25% on a common-equity ratio of 51.0%. SPS is also asking for an interim rate increase of $18 million. A final order is expected in early 2009.

**Other rate cases are pending or under consideration.** In addition to the aforementioned general rate case, SPS is seeking a wholesale tariff hike of $14.9 million (5.1%) based on a 12.2% return on equity and a $16.6 million (6.3%) increase in New Mexico based on an 10.7% return on a common-equity ratio of 51.2%. The commission's staff is proposing an $8 million boost based on a 9.1% ROE and a hearing examiner is recommending $12.6 million based on a 10.14% ROE. A ruling is expected this summer. PS of Colorado, which requested a wholesale increase of $8.8 million based on an 11.5% ROE, settled for a raise of $6.5 million. Northern States Power (NSP) wants a $17.9 million (12.2%) increase in North Dakota based on an 10.75% return on a 51.77% common-equity ratio, but the commission's staff is recommending a $4.9 million increase. A decision is expected this fall. Finally, PS of Colorado and NSP (in Minnesota) are evaluating the need for rate filings.

**Rate relief should continue driving earnings growth.** Besides the base rate increases that Xcel's utilities are receiving every year, the company also has rate riders that allow it to recover certain capital investments without a full-blown rate case. These will amount to an estimated $166 million this year and $195 million in 2009. We think that Xcel's 2008 share-earnings goal of $1.45-$1.55 is reasonable, and we look for a modest bottom-line increase next year.

**The board of directors increased the annual dividend by $0.03 a share (3.3%).** This is in line with Xcel's target of dividend growth of 2%-4% annually.

**This stock offers an attractive yield and decent dividend-growth potential.** Although the heavy rate case schedule raises regulatory risk, Xcel has managed the regulatory process ably, so far. Prospective total returns over the 3- to 5-year period are unspectacular, however.

*Paul E. Debbas, CFA* *August 8, 2008*

(A) Diluted EPS. Excl. nonrec. loss: '02, $6.27; gains (losses) on discont. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '05, 1¢. '06 & '07 EPS don't add due to rounding. Next earnings report due late Oct. (B) Div'ds historically paid in mid-Jan., Apr., July, and Oct. ■ Div'd reinvest. plan avail. (C) Incl. intang. In '07: $3.93/sh. (D) In mill., adj. for split. (E) Rate base: Varies. Rate all'd on com. eq.: MN '93, 11.47%; WI '08, 10.75%; CO '03 (elec.), 10.75%; CO '07 (gas) 10.25%; TX '86, 15.05%; earned on avg. com. eq., '07: 9.5%. Regulatory Climate: Average.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 5 |
| Earnings Predictability | 45 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 18**

**Responding Witness: William E. Avera**

Q-18. Refer to pages 26-27 of the Avera Testimony. Provide a copy of the workpapers supporting the constant growth of the DCF model and a detailed explanation of how the stock prices were estimated to determine the expected dividend yield.

A-18. Please refer to Dr. Avera's work papers provided in response to AG-1 Question No. 89 for documentation supporting his application of the constant growth DCF model. Specifically, please refer to WEA-WP33 through WEA-WP38 for work papers supporting the DCF analysis for the Utility Proxy Group. Work papers supporting the DCF analysis for the Non-Utility Proxy Group can be found at WEA-WP39 through WEA-WP42. Dr. Avera did not estimate any stock prices shown on Schedule WEA-1 that were used to determine the expected dividend yield. As indicated in footnote (a) on Schedule WEA-1, stock prices for the firms in the Utility Proxy Group were based on those reported by Value Line in the May 9, 2008 edition of its *Summary and Index*, with copies of these documents being provided in response to the AG-1 Question No. 89 at WEA-WP34.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 19**

**Responding Witness: William E. Avera**

Q-19. Refer to page 34 of the Avera Testimony.

a. Provide a copy of the relevant pages in the Federal Energy Regulatory Commission ("FERC") document cited in footnote 50 that discuss FERC's rationale and decision with regard to rate of return and "extreme outliers."

b. What was the reference point to which the 17.7 percent was compared?

c. Is the FERC decision establishing a 17.7 percent DCF estimate as an "extreme outlier" specific to that particular 2004 case or was it meant to be a hard and fast rule to be applied as a ceiling in all cases thereafter? Explain the response.

A-19. a. A complete copy of the document cited in footnote 50 to Dr. Avera's testimony is attached.

b. As reflected in the document provided in response to subpart (a), above, FERC did not cite a specific reference point in supporting its finding that a 17.7 percent cost of equity estimate was an extreme outlier.

c. On its own, the document provided in response to subpart (a), above, does not establish a bright line test with respect to FERC's evaluation of extreme high-end outliers; however, FERC has applied the finding of this decision in subsequent cases, including, for example, *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 (2008), with a copy being attached.

**Attachment to Response to PSC-2 Question No. 19(a)**
**Responding Witness – William E. Avera**

109 FERC ¶ 61,147

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

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| ISO New England, Inc., et al. | Docket Nos. RT04-2-001, RT04-2-002, RT04-2-003, RT04-2-004, ER04-116-001, ER04-116-002, ER04-116-003, and ER04-116-004 |
| Bangor Hydro-Electric Company, et al. | Docket Nos. ER04-157-002, ER04-157-003, ER04-157-005, and ER04-157-007 |
| The Consumers of New England v. New England Power Pool | Docket Nos. EL01-39-001, EL01-39-002, EL01-39-003, and EL01-39-004 |
| New York Independent System Operator, Inc. and the New York Transmission Owners | Docket No. ER04-943-000 |
| New England Power Pool | Docket No. ER05-3-000 |

ORDER ACCEPTING PARTIAL SETTLEMENT,
SUBJECT TO CONDITIONS; ACCEPTING, IN PART,
COMPLIANCE FILINGS; AND Granting, IN PART, AND
DENYING, IN PART, REQUESTS FOR REHEARING

(Issued November 3, 2004)

1. On September 14, 2004, the New England Power Pool (NEPOOL), ISO New England, Inc. (ISO-NE), and the New England transmission owners[1] (Transmission Owners) (collectively, the Settling Parties) submitted for approval, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure,[2] a Settlement Agreement seeking to resolve, in part, pending issues relating to the proposal made in this proceeding by ISO-NE and the Transmission Owners (collectively, the Filing Parties) to establish a regional transmission organization (RTO) for New England (the ISO-NE RTO). The Filing Parties' proposal was initially addressed by the Commission in an order issued March 24, 2004.[3] In that order, we found that the Filing Parties' proposal would, with modifications, comply with our minimum characteristics and functions for RTOs, as set forth in Order No. 2000.4

2. Rehearing and/or clarification of the March 24 Order was subsequently sought by numerous intervenors, while filings seeking to comply with our rulings were submitted by the Filing Parties on June 22, 2004 and August 11, 2004. In the meantime, settlement negotiations were undertaken by the parties pursuant to the settlement procedures established by the Commission in the March 24 Order. The Settling Parties state that their proposed Settlement Agreement was the product of these negotiations.5

3. The Settling Parties state that the Settlement Agreement, if approved, would resolve a number of the issues currently pending in this proceeding, while leaving for

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[1] Bangor Hydro Electric Company; Central Maine Power Company; NSTAR Electric & Gas Corporation; New England Power Company; Northeast Utilities Service Company; NSTAR Electric & Gas Corporation; The United Illuminating Company; and Vermont Electric Power Company.

[2] 18 C.F.R. § 385.602 (2004).

[3] ISO New England, Inc., *et al.*, 106 FERC ¶ 61,280 (2004) (March 24 Order).

[4] Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (2000), FERC Stats. & Regs. ¶ 31,089 (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (2000), FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd*, Public Utility District No. 1 of Snohomish County, Washington v. FERC, 272 F.3d 607 (D.C. Cir. 2001).

[5] On October 19, 2004, the Settlement Judge issued an order certifying the Settlement Agreement to the Commission.

resolution, herein, only a limited number of remaining issues raised either on rehearing and/or in response to the compliance requirements set forth in the March 24 Order (Reserved Issues). The Settling Parties state that, among other things, the Settlement Agreement would transfer to the ISO-NE RTO, NEPOOL's existing interests and assets under the currently-effective ISO-NE/NEPOOL arrangements, and provide for the determination and implementation of an ISO-NE RTO Operations Date.[6]

4. The Settling Parties state that the existing ISO-NE/NEPOOL arrangements would be replaced by the agreements conditionally accepted by the Commission in the March 24 Order, namely: (i) an ISO-NE RTO Tariff (including, for the most part, provisions previously accepted by the Commission under the ISO-NE/NEPOOL arrangements); (ii) a Participants Agreement; (iii) a Market Participants Service Agreement; and (iv) a Transmission Operating Agreement. In addition, the Settling Parties submit, as an exhibit to the Settlement Agreement, a Second Restated NEPOOL Agreement, pursuant to which NEPOOL would continue to exist as an advisory stakeholder body.

5. For the reasons discussed below, we will accept the Settlement Agreement, subject to conditions. We will also accept, in part, the Filing Parties' compliance filings and will grant, in part, and deny, in part, the remaining requests for rehearing, i.e., those requests for rehearing and/ or clarification identified in the Settlement Agreement as Reserved Issues.[7]

## I. Background

6. On October 31, 2003, the Filing Parties submitted their RTO proposal for filing. In that submittal, the Filing Parties proposed to establish the ISO-NE RTO as the provider of regional transmission service in the six-state New England region currently served by ISO-NE under the ISO-NE/NEPOOL arrangements. The Filing Parties also sought a declaration that the existing contractual arrangements governing the operation of

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[6] *See* Settlement Agreement at Attachment D. "Operations Date" is defined in the Transmission Operating Agreement, at section 10.01(a), as the date at least 30 calendar days following Notice to the Commission that ISO-NE and the Initial Participating Transmission Owners have unanimously agreed to place the ISO-NE RTO arrangements into effect. The Settlement Agreement further provides that such Notice shall not be issued until the earlier of November 1, 2004, or the date on which the Commission issues an order accepting the Settlement Agreement, without modification.

[7] For the reasons discussed below, we will also accept two related filings involving the proposed elimination of Through-and-Out Service Charges.

the New England markets would terminate as of the Operations Date of the ISO-NE RTO. In addition, the Transmission Owners, joined by Green Mountain Power Corporation and Central Vermont Public Service Corporation (the ROE Filers), submitted a related filing, pursuant to section 205 of the Federal Power Act (FPA),[8] in which they proposed a return on equity (ROE) recoverable under the regional and local transmission rates that will be charged by the ISO-NE RTO.[9]

7. In the March 24 Order, we found that the Filing Parties' proposal to establish the ISO-NE RTO will comply with the minimum characteristics and functions applicable to RTO operations as set forth by the Commission in Order No. 2000, subject to certain specified conditions.[10] As requested by the ROE Filers, we also accepted a 50 basis point ROE adder, applicable to Regional Network Service under the ISO-NE open access transmission tariff (OATT), but rejected this same adder as it would apply to the Transmission Owners' Local Service Schedules. We also rejected the ROE Filers' proposed 100 basis point adder as it applied to the ROE Filers' Local Service Schedules, but set for hearing, subject to suspension and refund, the ROE Filers' proposed 100 basis point adder as it would apply to Regional Network Service. Finally, we set for hearing, subject to suspension and refund, the ROE Filers' proposed base level ROE.

## II. <u>Requests for Rehearing and/or Clarification</u>

8. Requests for rehearing and/or clarification of the March 24 Order were sought by numerous intervenors on a broad range of issues. Certain of these issues, namely, those issues identified by the Settling Parties in their proposed Settlement Agreement as Reserved Issues, i.e., issues not resolved by the Settlement Agreement, are discussed

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[8] 16 U.S.C. § 824d (2000).

[9] Specifically, the ROE Filers requested approval for: (i) a single, region-wide ROE; (ii) a 50 basis point adder attributable to their formation of the ISO-NE RTO; and (iii) a 100 basis point adder applicable to new construction.

[10] Among other things, we required the Filing Parties to submit, in a compliance filing, a seams resolution agreement with the New York Independent System Operator, Inc. (New York ISO), and an agreement with NEPOOL concerning the procedures pursuant to which the ISO-NE RTO would be permitted to acquire NEPOOL's reversionary interests in ISO-NE under the ISO-NE/NEPOOL arrangements. We also required the Filing Parties to make various other specified revisions to the operating agreements giving rise to the ISO-NE RTO.

below.

9. Answers to requests for rehearing were filed by a number of parties: (i) on April 30, 2004, by the Massachusetts Attorney General, the Rhode Island Attorney General, and the Rhode Island Division of Public Utilities and Carriers (Massachusetts Attorney General, et al.); (ii) on May 5, 2004, by Duke Energy North America, LLC (Duke Energy); (iii) on May 10, 2004, by NEPOOL, ISO-NE, the Transmission Owners, and the New England Consumer Owned Entities[11]; and (iv) on May 25, 2004, by NEPOOL and the New England Consumer Owned Entities.

## III. Compliance Filings

10. The Filing Parties made their initial compliance filing in response to the March 24 Order on June 22, 2004 (First Compliance Filing). The First Compliance Filing includes, among other things: (i) a revised Interregional Coordination Agreement between ISO-NE and the New York ISO; (ii) a revised Transmission Operating Agreement; (iii) new planning procedures, including an identification of market efficiency upgrades and a discussion of how cost-effective transmission expansion solutions are assessed; and (iv) revisions to the ISO-NE RTO's Transmission, Markets and Services Tariff.[12]

11. In the transmittal sheet accompanying their submittal, the Filing Parties state that ISO-NE and the Transmission Owners were unable to reach agreement with respect to certain compliance matters. Specifically, the Filing Parties state that they were unable to reach an agreement on revising the Transmission Operating Agreement to comply with the Commission's directives regarding the Transmission Owners' RTO termination and withdrawal rights.[13] Accordingly, the Filing Parties, in their First Compliance Filing, include alternative proposals addressing this issue. Finally, the Filing Parties note that the First Compliance Filing leaves unaddressed NEPOOL's reversionary interests in the

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[11] Connecticut Municipal Electric Energy Cooperative, Massachusetts Municipal Wholesale Electric Company, Vermont Public Power Supply Authority, New Hampshire Electric Cooperative, Inc., Chicopee Municipal Lighting Plant of the City of Chicopee, Massachusetts, Braintree Electric Light Department, Reading Municipal Light Department, and Taunton Municipal Lighting Plant.

[12] The Tariff is comprised of four sections, including: (i) General Terms and Conditions; (ii) the OATT; (iii) Market Rule 1; and (iv) the ISO-NE RTO Funding Tariffs. In addition, the Market Participants Service Agreement and a *Pro Forma* Independent Transmission Company Operating Agreement are included in the Tariff as Attachments A and B, respectively.

[13] *See* March 24 Order at P 59.

assets attributable to the ISO-NE/NEPOOL arrangements (an issue, as noted below, that was subsequently addressed by the Settling Parties' in their proposed Settlement Agreement).

12. Notice of the Filing Parties' First Compliance Filing was published in the *Federal Register*,[14] with interventions and protests due on or before August 20, 2004. Notices of intervention, motions to intervene and protests were filed by NEPOOL, Calpine Eastern Corporation[15] (Calpine, et al.), Duke Energy, the Connecticut Department of Public Utility Control (Connecticut PUC), the Vermont Public Service Board, the Long Island Power Authority and its subsidiary, LIPA (LIPA), the New England Conference of Public Utility Commissioners (NECPUC), and the New England Consumer Owned Entities. An answer to LIPA's protest was filed on August 11, 2004, by the New York ISO. On August 26, 2004, LIPA filed an answer to an answer.

13. On August 11, 2004, the Filing Parties made a second compliance filing addressing our requirement, in the March 24 Order, regarding the sharing of confidential information between the ISO-NE RTO and state commissions (Second Compliance Filing) . Notice of the Filing Parties' Second Compliance Filing was published in the Federal Register,[16] with interventions and protests due on or before September 1, 2004. Comments were filed by NECPUC.

## IV. <u>The Proposed Settlement Agreement</u>

14. As noted above, the Settling Parties filed their proposed Settlement Agreement on September 14, 2004. The Settling Parties state that those provisions of the Settlement Agreement addressing NEPOOL's reversionary interests following the termination of the ISO-NE/NEPOOL arrangements (see Settlement Agreement at paragraph 8) are intended to comply with the requirements of the March 24 Order.[17] In compliance with these

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[14] 69 Fed Reg. 40,889 (2004).

[15] Joined by Mirant Americas Energy Marketing, LP; Mirant New England, Inc.; Mirant Canal, LLC; Mirant Kendall, LLC; and PSEG Energy Resources & Trade LLC.

[16] 69 Fed. Reg. 52,245 (2004).

[17] In the March 24 Order, we found that the Transmission Owners are permitted under their existing arrangements with NEPOOL to withdraw from the Restated NEPOOL Agreement and are entitled, along with ISO-NE, to file the necessary agreements to establish the ISO-NE RTO. However, we also held that any such proposal

(continued...)

directives, the Settling Parties state that the tangible assets constituting the NEPOOL Assets, under the Interim Independent System Operator Agreement (ISO Agreement), will be transferred to the ISO-NE RTO as of the ISO-NE RTO Operations Date.[18] The Settling Parties state that, following the start-up of the ISO-NE RTO, neither NEPOOL nor any NEPOOL Participant will have any interest in any tangible assets of the ISO-NE RTO.

15. The Settling Parties state that under paragraphs 9, 10, and 15 of the Settlement Agreement, the Settling Parties have agreed to withdraw their requests for rehearing and/or their requests for clarification of the March 24 Order, as well as their objections to the Filing Parties' First and Second Compliance Filings, except as to certain specified "Reserved Issues."[19] Reserved Issues not addressed by the proposed Settlement Agreement include: (i) all issues relating to the ISO-NE RTO's return on equity; (ii) the majority of the issues raised on rehearing by the Transmission Owners; (iii) Mirant's issue, raised on rehearing, regarding whether the ISO-NE RTO should have immediate section 205 filing rights under the "exigent circumstances" described under certain provisions of the proposed Transmission Operating Agreement; (iv) indemnification issues raised on rehearing by ISO-NE; (v) issues relating to the establishment of Independent Transmission Companies and economic transmission expansion, as raised on rehearing by Public Service Electric and Gas Company[20] (PSEG); and (vi) assertions of error raised on rehearing by the New England Consumer Owned Entities.

16. The Settling Parties state that under paragraph 9 of the Settlement Agreement, an 18-month moratorium will be in effect as of the Operations Date of the ISO-NE RTO. The Settling Parties state that during the course of the moratorium, a Settling Party may not seek changes, pursuant to a section 206 filing, regarding issues addressed by the Settlement Agreement, except in the case of materially changed circumstances, or for

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would not, *ipso facto*, terminate NEPOOL's existence and that NEPOOL, under its existing arrangements, possessed certain reversionary interests in the assets attributable to the ISO-NE/NEPOOL arrangements. We also held that these reversionary interests could serve to impede the ISO-NE RTO's efficient start-up. Accordingly, we directed the Filing Parties to identify the nature and extent of these reversionary interests and to propose, in their compliance filing, options for acquiring these interests.

[18] *See* Settlement Agreement at Attachment K (proposed Bill of Sale between ISO-NE and NEPOOL). The term "Operations Date" is discussed *supra* note 6.

[19] See supra P 3.

[20] Joined by PSEG Power LLC and PSEG Energy Resources & Trade LLC.

those filings involving proposed market rule changes.

17. The Settling Parties note that the Settlement Agreement was supported by a 91 percent affirmative vote of the NEPOOL Participants Committee and that approval of the Settlement Agreement, by the Commission, will remove most of the remaining obstacles to the establishment of the ISO-NE RTO. The Settling Parties request that the Commission act on their proposed Settlement Agreement no later than November 1, 2004, consistent with the planned Operations Date of the ISO-NE RTO.

18. Notice of the Settling Parties' proposed Settlement Agreement was published in the *Federal Register*,[21] with interventions and protests due on or before October 22, 2004. Comments were filed by NECPUC, the Connecticut Attorney General, the Connecticut Office of Consumer Counsel, NEPOOL, and ISO-NE.

## V. Proposed Elimination of Through-and-Out Service Charges

19. On June 21, 2004 and September 30, 2004, respectively, the New York ISO and the New York Transmission Owners[22] (New York Filing Parties), in Docket No. ER04-943-00, and NEPOOL, in Docket No. ER05-3-000, submitted proposed tariff revisions to their respective tariffs, pursuant to section 205 of the FPA, in order to reduce to zero the Through-and-Out Services Charges applicable in their regions.

20. Notice of the New York Filing Parties' and NEPOOL's proposed tariff changes was published in the *Federal Register*,[23] with interventions and protests due on or before July 12, 2004 (in Docket No. ER04-943-000) and October 22, 2004 (in Docket No. ER05-3-000). Motions to intervene and notices of intervention were timely filed by Mirant Corporation, the New York Municipal Power Agency (New York Municipal), and the New York State Department of Public Service, in Docket No. ER04-943-000, and by the Massachusetts Department of Telecommunications and Energy, ISO-NE, Northeast Utilities Service Company, and the New York Filing Parties, in Docket No. ER05-3-000. A motion to intervene out-of-time was filed, in Docket No. ER05-3-000, by DC Energy,

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[21] 69 Fed Reg. 59,912 (2004).

[22] Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., LIPA, New York Power Authority, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation.

[23] 69 Fed Reg. 48,734 and 71,302 (2004).

LLC (DC Energy). In addition, a protest was filed, in Docket No. ER04-943-000, by New York Municipal.

## VI. Discussion

### A. Procedural Matters

21. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[24] the notices of intervention and the timely, unopposed motions to intervene submitted in Docket Nos. ER04-943-000 and ER05-3-000, by the entities noted above, serve to make these entities parties to the proceedings in which these interventions were filed. In addition, we will accept the unopposed, late-filed intervention submitted by DC Energy in Docket No. ER05-3-000.

22. Rule 213(a) of the Commission's Rules of Practice and Procedure[25] prohibits an answer to a protest, an answer to a rehearing request, or an answer to an answer, unless otherwise permitted by the decisional authority. We are not persuaded to accept the answers filed by the entities noted above and therefore will reject them.

### B. NEPOOL's Reversionary Interests

23. In the March 24 Order, we found that the Transmission Owners are permitted under their existing contractual commitments to NEPOOL to withdraw from the ISO-NE/NEPOOL arrangements.[26] We also held that the Filing Parties were entitled to file the necessary agreements to establish the ISO-NE RTO. However, we denied the Filing Parties' request that their existing ISO-NE/NEPOOL arrangements be deemed to be terminated as of the Operations Date of the ISO-NE RTO. Instead, we required the Filing Parties to make a compliance filing addressing, among other things, NEPOOL's reversionary interests in the assets attributable to the ISO-NE/NEPOOL arrangements and the terms pursuant to which these interests can be transferred to the ISO-NE RTO.

24. The Settling Parties state that under the Settlement Agreement all pending issues relating to these matters would be resolved. Specifically, the Settling Parties state that under the Settlement Agreement NEPOOL's reversionary interests in the ISO-

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[24] 18 C.F.R. § 385.214 (2004).

[25] *Id.* at § 385.213(a)(2).

[26] March 24 Order at P 28.

NE/NEPOOL arrangements would be transferred by way of a Bill of Sale, to be executed by ISO-NE and NEPOOL.[27] The Settling Parties state that pursuant to the Bill of Sale, the tangible assets constituting the NEPOOL Assets, under the Interim ISO Agreement, would be transferred to the ISO-NE RTO as of the ISO-NE RTO Operations Date. As of that date, the Settling Parties state that neither NEPOOL nor any NEPOOL Participant would have any interest in any tangible assets of the ISO-NE RTO.

25. We find that the proposed Bill of Sale will assist the Filing Parties in providing for an orderly transition to the ISO-NE RTO and otherwise complies with the requirements of the March 24 Order. As such, we will accept this aspect of the proposed Settlement Agreement without modification.

### C. Governance Structure

26. In the March 24 Order, we found that the Filing Parties' proposed governance structure for the ISO-NE RTO generally met our RTO independence requirement, subject to three conditions.[28] First, we required the Filing Parties to include alternative energy suppliers as a sixth voting sector in the ISO-NE RTO stakeholder advisory process. Second, we modified the Filing Parties' proposal regarding the ISO-NE RTO's obligation to include alternative stakeholder proposals when making a section 205 filing.[29] Finally, we required that in nominating and electing a new ISO-NE RTO board, at least one new nominee must be named under those circumstances in which a second slate must be nominated.

27. The Settling Parties state that the Settlement Agreement satisfies each of these requirements. Specifically, the Settling Parties state that they have added a new sixth voting sector representing renewable interests, modified the necessary provisions of their proposed Participants Agreement relating to the submission of alternative stakeholder proposals, and amended the relevant provisions of the Participants Agreement addressing the ISO-NE RTO board nominations process. In addition, the Settling Parties proposed to retain those provisions of the Restated NEPOOL Agreement which address NEPOOL's stakeholder appeals process.

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[27] *See* Settlement Agreement at Attachment K.

[28] March 24 Order at P 51.

[29] We held that these alternative proposals must be included in the case of a Participants Committee vote of 60 percent or higher.

28. We will accept the Settlement Agreement as it relates to the governance structure issues addressed in the March 24 Order. However, we will require further support regarding the Settling Parties' proposed retention of certain requirements applicable to the NEPOOL appeals process. Section 11 of the Restated NEPOOL Agreement, as proposed, would keep in place NEPOOL's currently-effective review board appeals process, which gives stakeholders the right to appeal NEPOOL's actions and failure to take action. Section 11 would also authorize the review board to request that the ISO-NE RTO delay filing with the Commission any materials that are the subject of an appeal, with the ISO-NE RTO thereafter permitted "in its sole discretion ... to elect to delay or not delay any such filing."[30] .

29. However, given the potential of this provision to delay a filing that should be brought to the Commission's attention in a timely manner, we will require the Settling Parties, in a compliance filing to be made on or before 30 days following the date of this order, to explain in greater detail how the review board process will operate.

## D. RTO Termination and Withdrawal Rights

### 1. The March 24 Order

30. In the March 24 Order, we noted that the Filing Parties' proposed Transmission Operating Agreement addressed the right of a Transmission Owner to withdraw from the ISO-NE RTO. Specifically, proposed section 10.01(b) of that agreement would have permitted a Transmission Owner to unilaterally withdraw from the ISO-NE RTO upon the occurrence of certain stated conditions.[31] We rejected the Filing Parties' proposal because it would have prohibited any meaningful review by the Commission under section 205 of the FPA relating to a Transmission Owner's withdrawal from the ISO-NE RTO, even in those instances where revisions to the ISO-NE RTO's operating agreements would have been necessary.[32]

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[30] *See* Settlement Agreement at Exh. 6, Second Restated Agreement at section 11.7(e).

[31] The specified conditions included: (i) a default by the ISO-NE RTO; (ii) a change in federal policy concerning RTO formation matters; (iii) a Commission order revising the Filing Parties' division of their respective rights and duties; (iv) membership in an Independent Transmission Company; and (v) membership in another RTO following a merger or acquisition.

[32] March 24 Order at P 59.

(continued...)

31. Moreover, we found that the Filing Parties' proposal was inconsistent with our policy regarding RTO/ISO access and withdrawal rights.[33] Specifically, we noted that the RTO/ISO Access and Withdrawal Rights Policy Statement held, as a matter of Commission policy, that arrangements to join or exit an RTO or ISO must be reviewed by the Commission in the context of filings made under section 205. We also noted that this review is necessary in order to determine whether all of the elements contained in the filed arrangements meet the principles of Order No. 2000 and are otherwise just and reasonable under section 205 of the FPA. Accordingly, we required the Filing Parties to revise section 10.01(b) of the Transmission Operating Agreement.

### 2. Requests for Rehearing and/or Clarification

32. The Settling Parties state that under the Settlement Agreement, the requests for rehearing and/or clarification of the March 24 Order discussed below are identified as Reserved Issues.

33. First, the Transmission Owners seek clarification that compliance with the Commission's ruling regarding RTO termination and withdrawal rights simply requires clarifying language to section 10.01 of the Transmission Operating Agreement making clear the requirement that before a proposed termination or withdrawal can become effective, the requesting party would be obligated to make a section 205 filing in which it submits a replacement tariff, as may be required, and any other related arrangements necessary to effectuate the requested termination or withdrawal. The Transmission Owners assert that this interpretation of the March 24 Order is consistent with their proposal that the Mobile-Sierra public interest standard of review also apply to section 10.01.[34]

34. The Transmission Owners also seek rehearing regarding the Commission's determination, in the March 24 Order, that it would evaluate any request to withdraw from, or terminate, the ISO-NE RTO to determine, among other things, the extent to which the request satisfied the principles of Order No. 2000. The Transmission Owners assert that the Commission erred in making this determination because RTO

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[33] *Id., citing* Guidance on Regional Transmission Organization and Independent System Operator Filing Requirements under the Federal Power Act, 104 FERC ¶ 61,248 (2003) (RTO/ISO Access and Withdrawal Rights Policy Statement).

[34] *See* United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956).

participation, under Order No. 2000, is voluntary.

35. Finally, the Transmission Owners request clarification regarding the March 24 Order, at footnote 84, in which we cited our findings, as made elsewhere in our order, with respect to various provisions of the Transmission Operating Agreement. In footnote 84, we noted that to the extent that we had required these provisions to be revised, eliminated, or transferred to the ISO-NE RTO OATT, the Mobile-Sierra requests relating to these provision had, as a consequence, been rendered moot. On rehearing, the Transmission Owners seek clarification that footnote 84 was not intended by the Commission to modify, nullify or otherwise supercede our determinations regarding these provisions, including our finding regarding the Transmission Owners' termination and withdrawal rights under section 10.1 of the Transmission Operating Agreement.

### 3. Compliance Filings

36. The Filing Parties state that, in their First Compliance Filing, they were unable to reach an agreement regarding the appropriate revisions necessary to comply with our rulings in the March 24 Order regarding the issue of RTO termination and withdrawal rights. Specifically, the Filing Parties disagree as to whether the revisions required by the March 24 Order necessarily include the withdrawal of the Filing Parties' Mobile-Sierra request as it relates to section 10.01(f) of the Transmission Operating Agreement. The Transmission Owners argue that this revision was not required and therefore propose to leave their initially proposed Mobile-Sierra language intact, while adding language addressing the requirement that a section 205 filing also be made in the case of a requested termination or withdrawal from the ISO-NE RTO.[35]

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[35] As proposed by the Transmission Owners, section 10.01(f) would include the following language (shown in italics):

> (f) *Approvals.* Notwithstanding any other provision contained herein or in any other document to the contrary, any termination or withdrawal permitted by this Section 10.01 shall be effective unless the FERC finds that such termination or withdrawal is contrary to the public interest under the "*Mobile-Sierra* Doctrine". *Each [Participating Transmission Owner] exercising its right to withdraw or terminate in accordance with this section 10.01 shall file with the FERC, pursuant to section 205 of the FPA, the tariffs and rate schedules applicable to transmission service over such [Participating Transmission Owner's] Transmission Facilities to become effective upon such termination or withdrawal.*

### 4. Responsive Pleadings

37. ISO-NE and NECPUC argue that the Transmission Owners' proposal to retain their proposed Mobile-Sierra provision fails to comply with the March 24 Order and is otherwise inconsistent with Commission precedent. NECPUC asserts that the Transmission Owners' proposal would inappropriately shift the burden to non-Transmission Owners to prove that withdrawal is contrary to the public interest. ISO-NE also argues that a Mobile-Sierra provision, as applied to a Transmission Owners' right to withdraw from, or terminate, the ISO-NE RTO, is inconsistent with the RTO/ISO Access and Withdrawal Rights Policy Statement.

### 5. Commission Finding

38. We will grant rehearing, in part, and grant, in part, the requested clarifications of the March 24 Order as it relates to the Transmission Owners' termination and withdrawal rights under the Transmission Operating Agreement. We will also require the Filing Parties to make a compliance filing on, or before, 30 days following the issuance of this order, consistent with our findings below.

39. With respect to the issue of whether the Transmission Owners' Mobile-Sierra request can be reconciled with our requirement that a requested withdrawal or termination, under section 10.01, must be reviewed by the Commission under section 205 of the FPA, we find that: (i) the Filing Parties may bind themselves to a Mobile-Sierra standard, as requested, but that (ii) the Commission's review of any requested withdrawal or termination will be under the just and reasonable standard of section 205 of the FPA. In this regard, we agree with the Transmission Owners that our section 205 filing requirement, in the case of a requested withdrawal from, or termination, of the ISO-NE RTO (and the section 205 review, in this instance, contemplated by the March 24 Order), may be reconciled with a Mobile-Sierra provision applicable to these withdrawal rights, subject to the clarifications provided below.

40. The Transmission Owners' proposed language would permit "any termination or withdrawal [to become] effective unless the [Commission] finds that such termination or withdrawal is contrary to the public interest under the Mobile-Sierra Doctrine." We cannot accept this limitation. Section 205 review (as required by the March 24 Order) means that the Commission will determine whether an action under review is just and reasonable. Intervenors asserted in response to the Filing Parties' initial proposal,[36] and

[36]March 24 Order at P 112.

we agree on rehearing, that, a full, meaningful review by the Commission of a requested withdrawal from, or termination of, the ISO-NE RTO would not be possible where the Transmission Owner's rights to do so are governed by a standard of review that limits the application of the just and reasonable standard. Accordingly, we will require the Filing Parties to modify section 10.1(f) of the Transmission Operating Agreement to make clear that while a challenge to a section 10.01(f) request made by any of the parties to the Transmission Operating Agreement will be subject to the Mobile-Sierra doctrine, as proposed by the Transmission Owners, the Commission's own review of a requested withdrawal or termination will be made under section 205 of the FPA, i.e., the Commission's own review will not be limited by application of the Mobile-Sierra doctrine.[37]

41. We also deny the Transmission Owners' argument, on rehearing, that our review of a requested withdrawal from the ISO-NE RTO should not take into consideration our RTO formation policies under Order No. 2000. In considering the justness and reasonableness of any filing made under section 205, including an RTO withdrawal filing, the Commission is required to consider its policies and precedents, as may be relevant to the issues presented for our review. Although participation in an RTO is voluntary, a transmission owner's withdrawal can have a substantial impact on other market participants and the markets themselves. In these circumstances, the policies enunciated in Order No. 2000 would be relevant and must be considered.

42. Finally, we will grant the Transmission Owners' requested clarification regarding the findings we cited in footnote 84 of the March 24 Order. That summary of

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[37] Section 10.01(f), as modified, will provide as follows (with the required changes shown in italics):

> (f) Approvals. Notwithstanding any other provision contained herein or in any other document to the contrary, any termination or withdrawal *requested under* this Section 10.01 shall be effective, *subject to: (i) a showing by any party to this agreement seeking to challenge the request* that *the requested* termination or withdrawal is contrary to the public interest under the "Mobile-Sierra Doctrine;" *and (ii) the FERC's determination under section 205 of the FPA that the termination or withdrawal is just, reasonable and not unduly discriminatory or preferential.* Each [Participating Transmission Owner] exercising its right to withdraw or terminate in accordance with this section 10.01 shall file with the FERC, pursuant to section 205 of the FPA, the tariffs and rate schedules applicable to transmission service over such [Participating Transmission Owner's] Transmission Facilities to become effective upon such termination or withdrawal.

findings was not intended to modify, nullify, or otherwise supersede any of the findings in our order to which footnote 84 made reference.

### E. Section 205 Filing Rights

#### 1. The March 24 Order

43. In the March 24 Order, we accepted the Filing Parties' proposed allocation of their respective section 205 filing rights, subject to certain conditions relating to the filing of generator interconnection agreements.[38] Specifically, in response to intervenors' concerns regarding the authority that would be exercised by the Transmission Owners over the filing of interconnection agreements under section 2.05 of the Transmission Operating Agreement, and to ensure compliance with our pro forma interconnection procedures set forth in Order No. 2003,[39] we required the Filing Parties to make a compliance filing, as may be necessary, to conform their proposed provision with our order on the Filing Parties' pending Order No. 2003 compliance filing proceeding, in Docket No. ER04-433-000, *et al.*

44. Regarding the Transmission Owners' proposed reservation of section 205 filing rights for Transmission Upgrades relating to generator interconnections, we found that the proposed allocation was ambiguous in its meaning, and therefore required the Filing Parties to clarify their proposal, consistent with the requirements of Order No. 2003.[40] We held that to the extent the Transmission Owners were seeking to reserve filing rights for the pricing policy that would apply to generator interconnections, such a reservation of rights would be inconsistent with Order No. 2003 because the Transmission Owners were not independent entities.[41]

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[38] March 24 Order at P 71.

[39] Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 68 Fed. Reg. 49,845 (Aug. 19, 2003), FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, 106 FERC ¶ 61,220 (2004), *reh'g pending*

[40] The proposed provision was set forth at section 2.05(a)(ii) of the Transmission Operating Agreement.

[41] In Order No. 2003, we held that we would allow flexibility for variations from our *pro forma* interconnection requirements in those regions where an independent entity, such as an RTO, operates the regional transmission system. We stated that this treatment (continued...)

### 2. Requests for Rehearing

45. Rehearing requests addressed to the Commission's section 205 filing rights determinations in the March 24 Order were sought by the Transmission Owners and Mirant. The following Reserved Issues are identified in the Settlement Agreement.

46. The Transmission Owners request that to the extent the March 24 Order could be construed as a rejection of the interconnection-related section 205 filing rights provisions of the Transmission Operating Agreement, the Commission should reverse that finding and accept the Filing Parties' proposal under section 2.05(a)(ii) of the Transmission Operating Agreement to give the Transmission Owners joint section 205 filing authority over generator interconnection agreements and, second, accept the Filing Parties' proposal under section 3.04(b)(i) of the Transmission Operating Agreement to give Transmission Owners exclusive section 205 filing authority over the methodology by which the costs of Transmission Upgrades related to generator interconnections are allocated under the ISO-NE RTO OATT.

47. The Transmission Owners assert that under Atlantic City Electric Co. v. FERC,[42] the Commission may not require the Transmission Owners to cede section 205 filing rights, absent their voluntary consent. In addition, the Transmission Owners assert that the March 24 Order erroneously construed the requirements of Order No. 2003. Specifically, the Transmission Owners argue that while they are not independent entities, Order No. 2003 acknowledges the right of non-independent entities to make section 205 filings and to attempt to justify, therein, deviations from the Order No. 2003 pro forma requirements, relying on either a "regional differences" or "consistent with or superior to" rationale to support those proposed deviations.

48. Mirant asserts as error the Commission's failure in the March 24 Order to grant the ISO-NE RTO narrowly-circumscribed, but immediate section 205 filing rights in the case of "Exigent Circumstances." Mirant states that under section 3.04 of the Transmission Operating Agreement, as accepted by the Commission in the March 24 Order, the ISO-NE RTO would be required to wait 30 days to make a section 205 filing (where the Participating Transmission Owner and the ISO-NE RTO are unable to agree on such a filing), even when the reliability of the ISO-NE RTO bulk power system or the

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would be appropriate because the independent entity would have different operating characteristics than a non-independent entity and would be less likely to act in an unduly discriminatory manner than a Transmission Provider that is a market participant. *See* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at P 827.

[42] 295 F.3d 1 (D.C. Cir. 2002).

efficiency or competitiveness of the ISO-NE RTO markets may be at stake. Mirant concludes that in these circumstances, the ISO-NE RTO should be given the authority to make a section 205 filing without delay, provided that such filing not address the rates, charges or revenue requirement of any Participating Transmission Owner.

### 3. Compliance Filing and Responsive Pleadings

49. The Filing Parties, in their First Compliance Filing, assert that their initial proposal in this proceeding regarding their division of section 205 filing rights authority for generator interconnection agreements (sections 2.05(a)(ii) and 3.04(b)(i) of the Transmission Operating Agreement) was consistent with Order No. 2003 and should have been accepted by the Commission. The Vermont Public Service Board, however, takes issue with this assertion, characterizing this aspect of the Filing Parties' First Compliance Filing as a collateral attack of the March 24 Order. The Vermont Public Service Board requests a ruling from the Commission requiring the Filing Parties to comply with the March 24 Order as it relates to sections 2.05(a)(ii) and 3.04(b)(i) of the Transmission Operating Agreement.

### 4. Commission Finding

50. We will grant rehearing of the March 24 Order as it relates to the allocation of section 205 filing rights set forth in sections 2.05(a)(ii) and 3.04(b)(i) of the Transmission Operating Agreement. The Filing Parties' proposed allocation of filing rights under section 2.05(a)(ii) and 3.04(b)(i) is not inconsistent with Order No. 2003, because the pro forma requirements adopted in Order No. 2003 do not address the issue of filing rights in this context. Accordingly, we will address here, as requested, the merits of proposed sections 2.05(a)(ii) and 3.04(b)(i).

51. Section 2.05(a)(ii) provides, in relevant part, that with respect to the interconnection of a Large Generating Unit, the Interconnection Agreement shall be a three-party agreement among the Participating Transmission Owner, the ISO-NE RTO, and the Interconnecting Non-Party.[43] With respect to the interconnection of other Generating Units, the ISO-NE RTO shall be a party to an Interconnection Agreement if, and to the extent, the Commission's regulations require the ISO-NE RTO to be a party. We agree that this proposed allocation of section 205 filing rights is consistent with Commission policy and therefore will accept this provision, as proposed.

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[43] Similarly, in Docket No. ER04-433-000, *et al.*, NEPOOL proposes to revise section 11 of the *pro forma* Standard Large Generator Interconnection Procedures to provide for the execution and filing of three-party interconnection agreements.

52. Section 3.04(b)(i) delineates the section 205 filing authority for revenue requirements and their recovery through rates charged for all transmission facilities including (but not limited to) costs of transmission upgrades related to generator interconnections. We have previously held that the determination and allocation of revenue requirements and their recovery through rates charged are properly the right of the transmission owners. Accordingly, we will accept section 3.04(b)(i), as proposed.

53. We will also grant Mirant's request for rehearing. Mirant asserts that under the Filing Parties' proposed allocation of section 205 filing rights, a market flaw, if identified by the ISO-NE RTO, could not always be addressed by the ISO-NE RTO on a timely basis in the form of a section 205 filing, i.e., that under section 3.04(e), ISO-NE RTO would be required to delay a section 205 filing for 30 days where the Transmission Owners and the ISO-NE RTO are unable to mutually agree on the substance of the filing to be made. We agree with Mirant that section 3.04, as proposed, fails to give the ISO-NE RTO adequate authority to make such a filing. Moreover, section 3.04, as proposed, is generally inconsistent with the filing authority granted to the ISO-NE RTO under the Participants Agreement.[44] Accordingly, we will direct the Filing Parties to revise section 3.04, in a compliance filing, on or before 30 days following the issuance of this order. As revised, section 3.04 should grant to the ISO-NE RTO emergency filing authority consistent with the grant of filing authority recognized in the Participants Agreement in the case of Exigent Circumstances.

54. Finally, we will reject the Vermont Public Service Board's protest, given our acceptance, above, of sections 2.05(a)(ii) and 3.04(b)(i) of the Transmission Operating Agreement.

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[44] The Participants Agreement, at section 11.2, gives the ISO-NE RTO certain filing authority in the case of "exigent circumstances":

> In Exigent Circumstances, [the ISO-NE RTO] may unilaterally, upon written notice to the Participants Committee and Individual Participants, file with the Commission pursuant to section 205, if necessary, and implement a new or amended Market Rule, Operating Procedure, Manual, Reliability Standard, provision of the Information Policy (subject to 11.3), General Tariff Provision, or Non-[Transmission Owner] OATT Provision. Notwithstanding the generality of the foregoing, any change in the Information Policy shall be effective prospectively only and only for information received after such change becomes effective.

## F. Seams Resolution Agreement

### 1. The March 24 Order

55. In the March 24 Order, we found that the ISO-NE RTO generally met our RTO scope and regional configuration requirements, subject to conditions concerning certain interregional seams issues.[45] Specifically, while we noted the Filing Parties' commitment, to date, to address inter-regional seams issues on a regional basis, under a Interregional Coordination Agreement entered into by ISO-NE and the New York ISO, we also found that the timetable for addressing these issues must be pursued by the parties without delay. Accordingly, we conditioned our approval of an ISO-NE RTO on the Filing Parties' development of a more comprehensive seams agreement with the New York ISO.

56. Among other things, we required the Filing Parties to address in their revised seams agreement specific milestones and timelines for resolution of all remaining seams issues within one year of the date of the Filing Parties' First Compliance Filing. We also required the Filing Parties to submit a proposal for eliminating Through-and-Out Service Charges between the ISO-NE RTO and the New York ISO within six months of the date of the Filing Parties' First Compliance Filing. Finally, we stated that because the New York ISO has significant trade with its RTO neighbor to the south, PJM Interconnection, L.L.C. (PJM), the Filing Parties should also explain in their First Compliance Filing the role that PJM could play in the resolution of broader, regional seams issues. We stated that the Filing Parties should identify the specific remaining seams issues that require the participation and involvement of PJM.

### 2. Requests for Rehearing

57. On rehearing, the Transmission Owners assert as error (and the Settlement Agreement identifies as a Reserved Issue) the Commission's determination in the March 24 Order that the ISO-NE RTO's elimination of Through-and-Out Service Charges need not be conditioned on (i) the elimination of comparable New York ISO charges; or (ii) the establishment of a seams agreement between the ISO-NE RTO and the New York ISO.

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[45] March 24 Order at P 91.

### 3. Compliance Filings

58. In their First Compliance Filing, the Filing Parties state that on June 18, 2004, ISO-NE and the New York ISO executed an Amended and Restated Coordination and Seams Issue Resolution Agreement (Seams Resolution Agreement). The Filing Parties state that, under the Seams Resolution Agreement, specific milestones and timelines are provided for resolution of the remaining seams issues within one year of the date of the Filing Parties' First Compliance Filing. The Filing Parties state that among the issues that will be addressed, pursuant to this agreed-to timeline, are: (i) facilitated checkout procedures; (ii) regional resource adequacy; (iii) partial unit Installed Capacity Sales; (iv) elimination of rate pancaking; (v) cross-border controllable line scheduling; (vi) coordination of inter-regional planning; and (vii) the implementation of "Virtual Regional Dispatch."[46]

59. The Filing Parties state that the Seams Resolution Agreement also includes a work plan for ongoing identification of additional seams issues that, upon approval, will be added to the Seams Resolution Agreement. The Filing Parties state that the Seams Resolution Agreement also addresses PJM's involvement in seams resolution matters. Specifically, the Filing Parties state that PJM is, and will continue to be, a member of the Intermarket Coordination Group, a committee established under the Seams Resolution Agreement.

60. Finally, the Filing Parties address the Commission's requirement that Through-and-Out Service Charges be eliminated between the ISO-NE RTO and the New York ISO. The Filing Parties state that they are committed to complying with this directive and recognize the importance of eliminating these charges. In furtherance of this objective, the Filing Parties state that they will make a filing as soon as reasonably practicable and in a timeframe that allows full public comment on or before

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[46] Virtual Regional Dispatch would represent a new service offered by the ISO-NE RTO and the New York ISO to facilitate the physical dispatch of loads between these two markets for the purpose of promoting greater price convergence. Pursuant to the terms of the Seams Resolution Agreement, implementation of Virtual Regional Dispatch would occur in three phases. *See* Seams Resolution Agreement at Attachment 1, p. 3. In Phase I, a Virtual Regional Dispatch pilot program would be developed and implemented "as soon as practicable with a target date of the fourth quarter of 2004." Phase II would involve review of this pilot program and allow for its "potential" implementation in mid-2005. Phase III would include the review of the initial implementation of Virtual Regional Dispatch and further evaluation (in early 2006) of whether expanding Virtual Regional Dispatch would be warranted.

December 22, 2004. However, the Filing Parties also propose that the elimination of these charges be made contingent on the establishment of reciprocal terms of transmission access between the New York ISO and the ISO-NE RTO.

### 4. Responsive Pleadings

61. The New England Consumer Owned Entities characterize the Filing Parties' proposal to eliminate Through-and-Out Service Charges as a vague commitment at best. Similarly, LIPA argues that the Transmission Owners are continuing to delay and resist the elimination of these charges. In particular, LIPA objects to the Transmission Owners' insistence that their elimination of these charges be made contingent on the implementation of reciprocal terms of access vis a vis the New York ISO market. LIPA asserts that this condition is simply a restatement of the condition previously rejected by the Commission in the March 24 Order.

62. LIPA is also concerned about the implementation of cross border controllable line scheduling. LIPA asserts that while the Seams Resolution Agreement includes a milestone for the final resolution of this seams issue by June 2005, the Filing Parties should be required to provide regular progress reports to the Commission and market participants on its implementation and application to specific existing facilities. LIPA also asserts that further action is required by the Commission to ensure the timely resolution of additional and emerging seams issues. In particular, LIPA notes that there are a number of outstanding seams issues that have been identified in the Northeast ISO's quarterly seams report filed with the Commission that have yet to be given sufficient attention.

### 5. Commission Finding

63. We will deny, as moot, the Transmission Owners' request for rehearing, regarding the necessity for a reciprocity condition applicable to the ISO-NE RTO's elimination of its Through-and-Out Service Charges. With respect to these charges, the New York ISO has stated in its compliance filing, submitted in Docket No. ER04-943-000, that the elimination of its export charges will take place on the same date that a corresponding proposal applicable to the New England market becomes effective. NEPOOL's filing, in turn, submitted in Docket No. ER05-3-000, also proposes to eliminate NEPOOL's Through-and-Out Service Charge.[47]

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[47] NEPOOL's filing is not protested and, based on our review, has not otherwise been shown to be unjust or unreasonable or unduly discriminatory. Accordingly, we will accept NEPOOL's submittal for filing. We will also accept for filing the New York (continued...)

64. We will also accept the First Compliance Filing as it relates to our RTO scope and regional configuration requirements, subject to condition. First, we find that the Seams Resolution Agreement adequately addresses each of the seams issues identified by the Commission in the March 24 Order. However, we clarify, here, that the Virtual Regional Dispatch filing that the Filing Parties propose to submit for Commission review with a "target date" of the fourth quarter of 2004, i.e., the Filing Parties' proposed Phase I pilot program implementing Virtual Regional Dispatch, must be made by December 1, 2004. Further, we find that the Filing Parties' proposed timeline to resolve the remaining seams issues fail to comply with the requirements of the March 24 Order. As a result, we will condition our approval of the ISO-NE RTO on revision of the Seams Resolution Agreement to provide that, for each remaining seams issue, a proposal will be filed with the Commission 60 days prior to the implementation date of the proposal. We will also require the Filing Parties to clearly state the implementation dates in the Seams Resolution Agreement and to submit these revisions in a compliance filing to be made within 30 days of the date of this order. We find that these revisions will benefit all market participants are consistent with our goal of timely resolution of existing market seams that result in inefficiencies.

65. While we share LIPA's concern that continued oversight of the seams resolution process will be both appropriate and necessary, the Commission is fully prepared and able to carry out this monitoring function. Moreover, we will act promptly regarding any complaints that may be filed, as the Filing Parties proceed to implement the terms of the Seams Resolution Agreement. Finally, with respect to the identification of seams issues that may require the participation and involvement of neighboring markets, we note that under the Seams Resolution Agreement, the ISO-NE RTO and the New York ISO will be required to work closely with these third-party entities, including PJM and the Independent Market Operator of Ontario. We find that this commitment satisfies the requirements of the March 24 Order.

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Filing Parties' submittal and will deny the protest filed by New York Municipal. The New York Municipal asserts that while they do not contest the elimination of seams between the New York ISO and New England markets, the elimination of Through-and-Out Service Charges in the New York region could result in increased transmission rates and that these "costs" would not be outweighed by the "benefits" attributable to the New York Filing Parties' proposals. We disagree. For all the reasons discussed in the March 24 Order, the elimination of inter-regional seams will provide significant regional benefit for all market participants and the markets as a whole. Moreover, it has not been demonstrated that these benefits will be outweighed by any countervailing costs or burdens.

## G. The Cross Sound Cable

66. The March 24 Order granted LIPA's request with respect to its existing agreement for transmission service across the Cross Sound Cable merchant transmission facility. Specifically, we required the ISO-NE RTO, in the Merchant Transmission Operating Agreement it intends to negotiate with Cross Sound Cable LLC, to include appropriate grandfathering language to cover existing transmission service agreements, including LIPA's agreement. However, the agreement at issue has yet to be executed and filed by the parties. Accordingly, we will address the Filing Parties' compliance with this directive in the March 24 Order at such time as the agreement at issue is filed.

## H. Mobile-Sierra Provisions

### 1. The March 24 Order

67. The March 24 Order accepted certain of the Filing Parties' proposed Mobile-Sierra provisions, but required that other provisions of the Transmission Operating Agreement, for which Mobile-Sierra protection was requested, must be revised, eliminated, or transferred to the ISO-NE RTO OATT.[48] We noted, however, that because Mobile-Sierra protection may be appropriate with respect to at least some of these provisions, we would permit the Filing Parties to include in their compliance filing a fuller justification supporting their requests.

### 2. Requests for Rehearing

68. On rehearing, the Transmission Owners assert that the Commission erred in the March 24 Order in rejecting their requested Mobile-Sierra treatment covering each of the provisions of the Transmission Operating Agreement, as identified in their initial filing. First, the Transmission Owners assert that they have a statutory right to obtain Mobile-

[48] March 24 Order at P 131. Specifically, we rejected the Filing Parties' proposed provisions addressing billing (Transmission Operating Agreement section 3.10) and termination and withdrawal rights (Transmission Operating Agreement section 10.01). We also required that Transmission Operating Agreement section 3.10 be transferred to the ISO-NE RTO OATT. Finally, we required that Transmission Operating Agreement section 3.09 (planning and expansion) and schedule 10.05 (Independent Transmission Companies) be transferred to the RTO-NE OATT, and rejected section 10.05(b).

Sierra treatment for any portion of their agreement for which it is claimed. The Transmission Owners assert, in this regard, that the Mobile-Sierra doctrine provides the contracting parties the right to define their arrangements by contract and that any agreed-upon contractual limitations that bind the parties will also bind the Commission's authority to change the contract.

69. The Transmission Owners further assert that the rationale relied upon by the Commission in rejecting certain of the Filing Parties' Mobile-Sierra requests (i.e., that these provisions affected the rights and interests of other market participants or the performance and operation of the market as a whole) would prohibit any party required to file any contract with the Commission under section 205 of the FPA from seeking Mobile-Sierra protection, given the fact that any such contract, by definition, "affects" or "relates to" the wholesale sale or transmission of electricity in interstate commerce.

### 3. Compliance Filing and Responsive Pleadings

70. In their First Compliance Filing, the Filing Parties provide additional support for their contention that, as initially proposed, the Transmission Operating Agreement warrants Mobile-Sierra protection with respect to certain requested provisions (discussed below). The Filing Parties argue that each of these provisions delineates key rights and obligations of the Transmission Owners and the ISO-NE RTO, under the Transmission Operating Agreement, and that the Filing Parties, with respect to these provisions, deserve to be accorded contractual certainty as a condition to their commitment to establish a New England RTO.

71. The New England Consumer Owned Entities argue that because the fundamental workings of the ISO-NE RTO will involve a new division of rights and responsibilities among all market participants, it is critical that the agreements giving rise to these rights and responsibilities remain flexible and open to revision, as may be necessary. As such, the New England Consumer Owned Entities assert that the Filing Parties' have failed to demonstrate that any of the provisions addressed in the Transmission Operating Agreement should be accorded Mobile-Sierra treatment. In addition, the Vermont Public Service Board and NECPUC challenge the appropriateness of according Mobile-Sierra-treatment to specific provisions discussed below.

### 4. Commission Finding

72. We will deny the Transmission Owners' request for rehearing regarding the Commission's authority to review (and reject) their Mobile-Sierra requests under our just and reasonable standard. First, we disagree that the Commission is precluded from reviewing, in any substantive way, a request for Mobile-Sierra protection at the time that the underlying agreement at issue (in this case, the Transmission Operating Agreement) is initially filed for acceptance under section 205. Indeed, section 205 requires the

Commission to determine whether any such rate, term or condition submitted for our review is just and reasonable.

73. In the March 24 Order, we did just that. In making this determination, we stated that we would consider, among other things, whether the provision for which Mobile-Sierra protection is sought has an effect on non-parties to the agreement or the operation of the market as whole. The Transmission Owners respond (and we acknowledge) that, by definition, any agreement filed with the Commission under section 205 has at least some nexus with the broader interests of third-party market participants and the overall operation of the wholesale markets. However, where the interests of third-party market participants, or the effects on the market as a whole, are significant, we cannot find that a two-party agreement that would have the effect of limiting our ability to protect these broader interests is just and reasonable.

74. Accordingly, we reach, below, the underlying merits supporting the Filing Parties' requests for Mobile-Sierra treatment as they relate to each provision of the Transmission Operating Agreement at issue. For the reasons discussed below, we will accept, in part, and reject, in part, the Filing Parties' compliance filing as it relates to these requests. Specifically, we will grant Mobile-Sierra protection, as requested, applicable to the following provisions of the Transmission Operating Agreement: sections 3.01, 3.09, 3.11, 3.13, 4.01(e), 6.07, 11.04 (a)–(d), and 11.05. We will reject Mobile-Sierra protection applicable to sections 9.01, 9.06, 10.01, and 11.14. Section 10.05 must be removed from the Transmission Operating Agreement and we are not ruling on section 3.10 (which has been withdrawn by the Filing Parties).

75. ***Section 3.01 (grant of operating authority to the ISO-NE RTO).*** Section 3.01 of the Transmission Operating Agreement sets forth the grant of operating authority from the Participating Transmission Owners over their assets to the ISO-NE RTO and the ISO-NE RTO's assumption of such authority. Section 3.01 provides that, effective as of the Operations Date of the ISO-NE RTO, each Participating Transmission Owner will authorize the ISO-NE RTO to exercise Operating Authority over each Participating Transmission Owner's transmission facilities. Section 3.01 also sets forth limitations on the ISO-NE RTO's operating authority.

76. The Filing Parties assert that section 3.01 is a provision that works in tandem with section 3.02 (which defines the ISO-NE RTO's Operating Authority) and that, as such, Mobile-Sierra treatment is appropriate for the same reason already recognized by the Commission in the March 24 Order, as it relates to section 3.02.[49] We agree with the

[49] March 24 Order at P 129.

(continued...)

Filing Parties that section 3.01 works in close tandem with section 3.02, a provision for which we have already granted the Filing Parties' request for Mobile-Sierra protection, and that both provisions primarily affect the rights and interests of the Filing Parties. Accordingly, we will accept the Filing Parties' proposed Mobile-Sierra treatment for section 3.01.

77. ***Section 3.09 (transmission planning and expansion).***[50] The Filing Parties assert that Mobile-Sierra protection is warranted, as it relates to section 3.09, because prospective investors in new transmission facilities demand certainty when it comes to the planning and construction process. NECPUC objects, arguing that the underlying rights and obligations addressed by section 3.09, in its entirety, should be addressed in the ISO-NE RTO OATT, not the Transmission Operating Agreement.

78. We will grant Mobile-Sierra treatment, as requested by the Filing Parties. Section 3.09 provides direction to the Transmission Owners and the ISO-NE RTO to follow planning procedures contained in the ISO-NE RTO OATT. As such, this provision will have no adverse impact on third parties or the New England market. With respect to NECPUC's request for rehearing, we deny NECPUC's request to transfer section 3.09 and schedule 3.09(a) in their entirety to the OATT. Section 3.09 and sections 6 and 7 of schedule 3.09(a) concern general references to previously adopted planning procedures and do not belong in the more detailed ISO-NE RTO OATT.

79. ***Section 3.10 (collection and disbursement of payments).*** The Vermont Public Service Board points out that while the Filing Parties, in their First Compliance Filing, have deleted section 3.10 from their revised Transmission Operating Agreement (based on the Filing Parties' representation that this provision will be the subject of a future filing), it could still be inferred that Mobile-Sierra protection is being sought by the Filing Parties with respect to this provision. The Vermont Public Service Board argues that the Commission should reject any pre-approved Mobile-Sierra treatment. We agree with the Vermont Public Service Board and will not rule on Mobile-Sierra protection for this section on a pre-approved basis.

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[50] Section 3.09 sets forth the rights and obligations of the Participating Transmission Owners and the ISO-NE RTO with respect to system planning and expansion. Specifically, section 3.09 and its corollary provision, schedule 3.09(a), delineate the Transmission Owners' obligation to build in response to the regional needs as may be determined by the ISO-NE RTO. Section 3.09 also provides for the recovery of costs for such projects.

80. ***Section 3.11 (treatment of grandfathered agreements).***[51] The Filing Parties assert that Mobile-Sierra treatment is appropriate, as it relates to section 3.11, for the same reason justifying grandfathered treatment of the underlying transmission contracts, i.e., because these contracts represent negotiated rights and obligations which should not be abrogated. We agree. The Grandfathered Transmission Agreements will have no significant effect on market participants that are not parties to these agreements or on reliable operation of the New England market. Therefore, we will grant Mobile-Sierra treatment to section 3.11, as requested.

81. ***Section 3.13 (protection of municipal/tax exempt status).***[52] The Filing Parties argue that absent the assurance provided by section 3.13 (and the application of Mobile-Sierra treatment as it relates to this provision), tax-exempt municipalities may be reluctant to participate in an RTO. We find that section 3.13 primarily affects the municipal tax-exempt Transmission Owners to whom it applies. We also agree with the Filing Parties that section 3.13 provides a necessary incentive to tax-exempt municipalities to join the ISO-NE RTO. We will therefore grant Mobile-Sierra protection as it relates to section 3.13.

82. ***Section 4.01(e) (disclaimer of transmission facility warranties).***[53] The Filing Parties assert that Mobile-Sierra protection is appropriate as it relates to section 4.01 (e), consistent with the unique interests and needs of the Transmission Owners. We agree that the rights and obligations addressed by section 4.01(e) concern primarily the rights and obligations of the Participating Transmission Owners and the ISO-NE RTO alone. Accordingly, we will grant Mobile-Sierra treatment, as requested.

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[51] Section 3.11 provides that existing transmission agreements, as identified in Attachment G-1 and schedule 3.11(c) to the NEPOOL OATT (Grandfathered Transmission Agreements) will not be modified or abrogated following the establishment of the ISO-NE RTO.

[52] Section 3.13 provides that the Transmission Operating Agreement shall not be effective as to a municipal tax-exempt transmission owner unless and until that transmission owner's bond counsel renders an opinion that participation in the Transmission Operating Agreement will not adversely affect its tax-exempt status.

[53] Section 4.01(e) provides that Transmission Owners, in their grant of operating authority to the ISO-NE RTO, make no express or implied representations or warranties with respect to their transmission facilities.

83. ***Section 6.07 (requirements applicable to management agreements).***[54] The Filing Parties note that section 6.07 is designed to ensure that the ISO-NE RTO's contractual commitments are fair and non-discriminatory. The Vermont Public Service Board objects to the Filing Parties' request for Mobile-Sierra protection as it relates to this provision. The Vermont Public Service Board asserts that Mobile-Sierra protection is unnecessary because the asserted need (preventing discrimination) would be sufficiently addressed by the Commission itself, given the fact that the management agreements at issue must be filed with the Commission. We will grant Mobile-Sierra treatment, as requested. Section 6.07 will primarily affect the ISO-NE RTO, a party to the Transmission Operating Agreement and will not adversely affect the rights and interests of third parties. Moreover, application of a Mobile-Sierra provision as it relates to this requirement will facilitate, not deter, Commission oversight and review of the ISO-NE RTO's management agreements.

84. ***Section 9.01 (indemnification requirements) and Section 9.06 (assumption of liability).***[55] The Filing Parties note that while the Transmission Owners and the ISO-NE RTO have taken alternative positions with respect to these provisions, as reflected in the Transmission Owners' request for rehearing of the March 24 Order, the provisions themselves, once accepted, will represent a fundamental aspect of the Filing Parties' RTO formation proposal and should not be thereafter modified unless the Commission makes a public interest finding supporting such a revision. We agree that the issues addressed by sections 9.01 and 9.06 affect primarily the rights and interests of the Filing Parties alone. Accordingly, we will accept the Filing Parties' proposed Mobile-Sierra provision as it relates to these provisions.

85. ***Section 10.01 (term, default, and termination).*** For the reasons discussed above (see supra section D, regarding the Transmission Owners' RTO termination and

[54] Section 6.07 provides that the ISO-NE RTO will not enter into any management agreement relating to the provision of transmission services unless the agreement has: (i) been approved by the Commission; (ii) does not violate the ISO-NE RTO's Code of Conduct and is on an arms-length basis; and (iii) is the result of a competitive solicitation process, the outcome of which is based on skill, qualifications, costs, reputation, and associated risks.

[55] As noted in Section P of this order, below, section 9.01 of the Transmission Operating Agreement addresses the Filing Parties' obligations to indemnify the other with respect to third-party liabilities attributable to their respective acts and omissions. Section 9.06, by contrast, addresses the Filing Parties' respective liabilities covering their own claims against each other (*i.e.*, two-party claims).

withdrawal rights), we are rejecting the Filing Parties' Mobile-Sierra request as it relates to section 10.01 of the Transmission Operating Agreement.

86. ***Section 10.05 (Independent Transmission Companies)***. The Filing Parties continue to include section 10.05 in their request for Mobile-Sierra treatment. NECPUC points out that in the March 24 Order, the Commission required the Filing Parties to transfer its proposed provisions addressing the formation and operation of Independent Transmission Companies to the ISO-NE OATT. In the March 24 Order, we required that section 10.05 be removed from the Transmission Operating Agreement and placed in the ISO-NE RTO OATT. Below, we address the substance of the Filing Parties' Independent Transmission Company requests. For the reasons discussed below, we will require the Filing Parties to remove section 10.05 from the Transmission Operating Agreement and add it to the ISO-NE OATT. Accordingly, we need not address here the appropriateness of Mobile-Sierra treatment for this provision.

87. ***Section 11.04(a)-(d) (limitations on amendments to the Transmission Operating Agreement)***[56] The Filing Parties assert that absent a Mobile-Sierra provision applicable to section 11.04(a)-(d), third parties would be permitted to seek the modification of the Transmission Operating Agreement and thus undo the negotiated compromises reached by the ISO-NE RTO and the Transmission Owners in establishing the ISO-NE RTO. Section 11.04(c) must be revised to reflect the Mobile-Sierra determinations made herein. With that change, Mobile-Sierra protection will be given to section 11.04(a)-(d) because such a ruling is consistent with the provision-by-provision Mobile-Sierra analysis we have undertaken here.

88. ***Section 11.05 (additional Participating Transmission Owner).***[57] The Filing Parties assert that a Mobile-Sierra provision is appropriate with respect to section 11.05 in order to ensure proper coordination between all of the Participating Transmission Owners and the ISO-NE RTO. We agree that the rights and obligations addressed by

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[56] Section 11.04(a)-(d) sets forth the procedures for amending the Transmission Operating Agreement. Under section 11.04, any future amendment to the Transmission Operating Agreement will require the agreement of the ISO-NE RTO and a specified percentage of Transmission Owners, operating under an administrative committee structure. In addition, section 11.04(c) also sets forth those provisions that the Filing Parties seek to be protected under the *Mobile- Sierra* public interest standard of review.

[57] Section 11.05 sets forth the method by which a Transmission Owner can become a Participating Transmission Owner under the Transmission Operating Agreement.

section 11.05 concern primarily the interests of the Filing Parties themselves and that, as such, Mobile-Sierra treatment is warranted.

89. ***Section 11.14 (dispute resolution procedures).***[58] The Filing Parties assert that section 11.14 deserves Mobile-Sierra protection because this provision allows the Filing Parties and market participants to know what their rights and obligations are in connection with dispute resolution matters. The Vermont Public Service Board objects, pointing out that the negotiation period set forth in section 11.14 (not less than 60 calendar days) is too specific to be subject to such a high bar for review.

90. We will reject the Filing Parties' request to apply the Mobile-Sierra public interest standard of review to section 11.14. The matters addressed by section 11.14 expressly include obligations applicable to all market participants, i.e., to non-parties to the Transmission Operation Agreement. Specifically, section 11.14 states that, in the event of a dispute: "Each affected Party and each market participant shall designate one or more representatives with the authority to negotiate the matter in dispute to participate in such negotiations." We also note that an identical dispute resolution procedures provision exists in the ISO-NE RTO OATT, as directed by the Commission in the March 24 Order.[59] As such, providing Mobile-Sierra treatment to the Transmission Operating Agreement's dispute resolution procedures provision, section 11.14, would preclude the Commission from maintaining consistency with the ISO-NE RTO OATT concerning dispute resolution procedures. We will therefore reject Mobile-Sierra treatment for section 11.14 of the Transmission Operating Agreement.

## I. Independent Transmission Companies

### 1. The March 24 Order

91. The March 24 Order found that the Filing Parties' proposed procedures regarding the establishment and operation of Independent Transmission Companies within the ISO-NE RTO framework was generally consistent with the Commission's

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[58] Section 11.14 specifies the procedures for resolving disputes under the Transmission Operating Agreement. Section 11.14 requires the parties to engage in good-faith negotiations for at least 60 days in an effort to resolve their disputes unless exigent circumstances exist, or if other provisions of the Transmission Operating Agreement require a party to submit a dispute directly to the Commission for resolution. Any dispute not resolved through good-faith negotiations may be submitted for resolution by the Commission or a court or agency with jurisdiction over the dispute.

[59] March 24 Order at 173.

policies and precedents, subject to the following conditions: (i) the re-filing of the relevant procedures as revisions to the ISO-NE RTO OATT; (ii) clarification that an Independent Transmission Company's authority over rate discount matters was subject to the rate discount authorizations set forth in the ISO-NE RTO OATT; [60] (iii) clarification that the ISO-NE RTO would be given the final say over planning procedures; (iv) clarification regarding an Independent Transmission Company's authority over the development of Reliability Must Run related costs; and (v) clarification regarding the circumstances under which a project identified by an Independent Transmission Company could be incorporated into the ISO-NE RTO's Regional System Plan; and (vi) clarification regarding an Independent Transmission Company's authorization over line loss responsibility determinations.[61]

### 2. Requests for Rehearing

92. Rehearing of the Commission's findings in the March 24 Order, with respect to establishment and formation of Independent Transmission Companies, was sought by the Transmission Owners and PSEG. The following Reserved Issues are identified in the Settlement Agreement:

93. First, the Transmission Owners assert as error the Commission's rejection of the proposal that would have given an Independent Transmission Company the unilateral right to file with the Commission a mechanism for determining loss responsibility. The Transmission Owners note that this provision, as proposed, was limited in its application to circumstances where an Independent Transmission Company is financially responsible for line losses and was required to allocate the costs of these losses to their customers. The Transmission Owners submit that this limited right would have only applied where the Locational Marginal Prices for the region do not take line losses into account and only when the Independent Transmission Company is responsible for these costs.

94. PSEG asserts as error the Commission's acceptance in the March 24 Order of a framework that would permit the Independent Transmission Company to operate as a transmission provider. PSEG asserts, in this regard, that permitting an Independent Transmission Company to control transmission access would be the equivalent of allowing that entity to control access to the market itself, given the nexus between these

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[60] We also required the Filing Parties to clarify the effect of any such discounts on other market participants

[61] March 24 Order at P 149.

markets under a Locational Marginal Pricing paradigm. PSEG concludes that the Commission should not permit any transmission-owning entity, including an Independent Transmission Company, to control market access.

95. PSEG also asserts as error the Commission's determination in the March 24 Order that, as proposed by the Filing Parties, an Independent Transmission Company would be permitted to calculate Total Transmission Capacity, given its familiarity with the transmission facilities within its footprint. PSEG argues that an Independent Transmission Company should not, and cannot, calculate Total Transmission Capacity. PSEG asserts that calculating these figures requires a broad regional perspective. For this same reason, PSEG also argues, on rehearing, that an Independent Transmission Company should be permitted to play no role in billing, in determining protocols for transmission line-loading relief, in coordinating outage scheduling, in processing transmission service reservations, or in administering its tariff.

96. PSEG also seeks rehearing regarding the Commission's determination in the March 24 Order that an Independent Transmission Company would be permitted to exercise certain authority over rate discounting practices. PSEG argues that an Independent Transmission Company should be given no role in awarding discounts for transmission service over its facilities, whether or not the applicable tariff permits the discount. PSEG asserts that the fiduciary obligations of an Independent Transmission Company could require it to discriminate in favor of particular market participants. At a minimum, PSEG submits that the Commission should not permit such authority until the Filing Parties can adequately explain the potential implications and effects of these discounts. Finally, PSEG asserts as error the Commission's failure to require ISO-NE RTO monitoring with respect to all activities undertaken by the Independent Transmission Company.

### 3. Compliance Filing

97. In their First Compliance Filing, the Filing Parties state that they have complied with each of the requirements in the March 24 Order regarding the establishment and operation of Independent Transmission Companies. Specifically, the Filing Parties state that schedule 10.05 of their proposed Transmission Operating Agreement has been re-filed, with appropriate conforming changes, as new Attachment M to the ISO-NE RTO OATT. In addition, to clarify the circumstances under which a project identified by an Independent Transmission Company could be incorporated into the ISO-NE RTO's Regional System Plan, the Filing Parties propose to define the term "Material Adverse Effect" as a means of identifying those projects that will be excluded.[62]

[62] The Filing Parties propose to define "Material Adverse Effect" as follows:

(continued...)

98. The Filings Parties also state that they have modified section 7.1 of their proposed Independent Transmission Company procedures to address the Commission's findings in the March 24 Order regarding rate discounts. The Filing Parties state that revised section 7.1 makes clear that an Independent Transmission Company can only make decisions on rate discounts to the extent applicable under the rate design for the Independent Transmission Company Rate Schedule and to the extent rate discounting is authorized as to such transmission services.

99. The Filing Parties also clarify the role that an Independent Transmission Company would play in the development of Reliability Must Run-related costs. The Filing Parties state that the relevant provision (section 5.2 of their proposed Independent Transmission Company procedures), addresses Independent Transmission Company action to reduce congestion. The Filing Parties further state that this provision would not permit an Independent Transmission Company to exercise final authority in determining the costs that may be recovered through such contracts. The Filing Parties state that authority, rather, would rest with the ISO-NE RTO.

100. Finally, the Filing Parties state that that they have the complied with the directives of the March 24 Order by removing those provisions in their initially proposed Independent Transmission Company procedures relating to line losses.

### 3. <u>Responsive Pleadings</u>

101. The Vermont Public Service Board challenges the adequacy of the Filing Parties' explanation of the role that would be given to an Independent Transmission Company in the development of Reliability Must Run-related costs. The Vermont Public Service Board asserts that the explanation of this role, as provided by the Filing Parties in their First Compliance Filing, still leaves a number of unanswered questions. In

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> For purposes of review of [Independent Transmission Company]-proposed plans, a proposed facility or project will be deemed to cause a "material adverse impact" on facilities outside of the [Independent Transmission Company] System if: (i) the proposed facility or project causes non-[Independent Transmission Company] facilities to exceed their capabilities or exceed their thermal, voltage or stability limits, consistent with all applicable reliability criteria, or (ii) the proposed facility or project would not satisfy the standards set forth in section 1.3.9 of the [ISO-NE RTO] Tariff. This standard is intended to assure the continued service of all non-[Independent Transmission Company] Firm Load customers and the ability of the non-[Independent Transmission Company] systems to meet outstanding transmission service obligations.

particular, the Vermont Public Service Board notes that it is unclear what is intended by the representation that an Independent Transmission Company will have "certain authority" to take operating actions to reduce costs associated with transmission congestion. The Vermont Public Service Board requests that, among other things, the Commission require the Filing Parties to expressly provide, in Attachment M, that it is the ISO-NE RTO that has the ultimate authority over Independent Transmission Company operating actions taken pursuant to section 5.2 of Attachment M.

102. The Vermont Public Service Board also takes issue with the adequacy of the Filing Parties' proposed revisions to section 7.1 of Attachment M concerning the effects of rate discounts on other customers. The Vermont Public Service Board asserts that because rate discounting is not currently authorized (and because the impact on customers cannot be determined at this time), the Commission should require that this provision (section 7.1) be rejected as non-applicable.

### 4. Commission Finding

103. We will deny, in part, and grant, in part, rehearing, and accept, in part, and reject, in part, the Filing Parties' First Compliance Filing as it relates to those aspects of the March 24 Order concerning the establishment and operation of Independent Transmission Companies.

104. We will grant rehearing regarding the Transmission Owners' assertion that the Commission erred in its determination that an Independent Transmission Company may not have a unilateral right to file a mechanism for determining loss responsibility. In the March 24 Order, we based our rejection of this requested authority on the assumption that the provision at issue (section 6 of the Filing Parties' proposed Independent Transmission Company framework) could prejudge the appropriate allocation of costs that have yet to be quantified in a particular case. It would not. Section 6, as proposed, provides in its entirety, as follows:

> To the extent the [Independent Transmission Company] is responsible for the costs of losses, the [Independent Transmission Company] shall possess the unilateral right to file at FERC, without any [ISO-NE RTO] approval, a mechanism for determining loss responsibility with the [Independent Transmission Company] System, provided that this method does not affect the costs of losses assigned to entities other than the [Independent Transmission Company] in areas outside of the [Independent Transmission Company] System and is not inconsistent with design of the markets administered by [the ISO-NE RTO], including the congestion pricing methodology for the [ISO-NE RTO] region approved by the FERC and any provision for losses contained therein.

105. Section 6, on its face, does not propose to allocate loss responsibility. Moreover, as the Transmission Owners correctly point out in their rehearing request, the Commission has already approved the assignment of responsibility for calculation of line losses to an Independent Transmission Company participating in the Midwest ISO.[63] Accordingly, we will accept section 6, as proposed, for inclusion in the Filing Parties' Independent Transmission Company framework.

106. We will deny PSEG's request for rehearing regarding the authority of an Independent Transmission Company to calculate Total Transmission Capacity. Under the Filing Parties' proposed framework, as accepted in the March 24 Order, the Independent Transmission Company may determine Total Transmission Capacity consistent with the ISO-NE RTO's methodology and provide its calculations to the ISO-NE RTO. However, the ISO-NE RTO would (and must) have the final authority regarding these determinations, not the Independent Transmission Company, because the ISO-NE RTO will be responsible for matters relating to the short term reliability of the New England markets.

107. We will also deny PSEG's rehearing argument that an Independent Transmission Company should not be given the authority to institute Transmission Load Relief procedures. We clarify that the provision at issue (section 8 of the Independent Transmission Company framework) limits the authority that can be exercised by the Independent Transmission Company. Specifically, section 8 provides that the Independent Transmission Company shall develop protocols for the coordination of transmission service curtailments on the Independent Transmission Company system, subject to coordination with the ISO-NE RTO and in accordance with all applicable OATTs and operating procedures. In addition, as we stated in the March 24 Order, while the ISO-NE RTO and the representatives of the proposed Independent Transmission Company would be permitted to jointly develop and establish the Independent Transmission Company's authorized planning procedures, the ISO-NE RTO, not the Independent Transmission Company, would have the final say.[64]

108. We will also reject PSEG's argument that the Independent Transmission Company framework should be revised to allow the ISO-NE RTO to monitor all Independent Transmission Company activities. Under section 12 of the Independent Transmission Company framework, the Independent Transmission Company will rely upon ISO-NE RTO to determine if the division of functions creates a competitive or

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[63] *See* Commonwealth Edison Company, 90 FERC ¶ 61,192 at 61,626 (2000).

[64] March 24 Order at P 156.

reliability problem that affects the ISO-NE RTO's ability to provide efficient, reliable, and non-discriminatory service and administration of markets within the ISO-NE RTO region. We find the Independent Transmission Company proposal to rely upon ISO-NE RTO for this function reasonable, because the ISO-NE RTO has the broad regional perspective needed to properly assess whether competition in the bulk power market is being fostered.

109. We will deny PSEG's rehearing request regarding the level of responsibility that should be given to an Independent Transmission Company with respect to billing matters. In fact, allowing the Independent Transmission Company to bear the primary responsibility for billing matters, as proposed by the Filing Parties, is appropriate where, as here, the ITC will also have responsibility for a number of related duties and functions (e.g. maintaining its own rate schedules and overseeing its rate discounting practices and line loss calculations). Moreover, the Independent Transmission Company's billing responsibility, as proposed, is generally consistent with the procedures followed by PJM and the Midwest ISO.

110. We will deny PSEG's argument on rehearing, that our acceptance of the Independent Transmission Company framework would allow an Independent Transmission Company to operate as a transmission provider. Section 7.1 of the Independent Transmission Company framework provides that the ISO-NE RTO will be the transmission provider under the OATT of non-discriminatory open access transmission service over the Independent Transmission Company system.

111. We will also deny PSEG's rehearing argument that Independent Transmission Companies should have no role in developing operational protocols. As we stated in the March 24 Order:

> While under the Filing Parties' proposal, the ISO-NE RTO and the representatives of the proposed Independent Transmission Company would be permitted to jointly develop and establish the Independent Transmission Company's authorized planning procedures, moreover, the [ISO-NE] RTO, not the Independent Transmission Company would have the final say. Specifically, in the event any dispute arises regarding the terms and conditions of these procedures, the [ISO-NE] RTO would be authorized to submit its proposal directly to the Commission.[65]

112. With respect to the arguments raised by the Vermont Public Service Board and PSEG regarding rate discounting authority, the Filing Parties have modified section 7.1

[65] *Id.* at P 156.

of their proposed Independent Transmission Company procedures to address the Commission's findings in the March 24 Order regarding rate discounts.66 The Filing Parties state that revised section 7.1 makes clear that an Independent Transmission Company can only make decisions on rate discounts to the extent applicable under the rate design for the Independent Transmission Company Rate Schedule, and to the extent rate discounting is authorized as to such transmission service. We clarify that to the extent that an Independent Transmission Company is developed in the ISO-NE RTO, the service schedule proposed may contain such rate discounts. Any discount provision allowed under an Independent Transmission Company rate design would not adversely affect the revenues of non-Independent Transmission Companies' transmission providers operating within the ISO-NE RTO region. Moreover, this rate discounting authority would be consistent with the policy set forth in Order No. 888.[67]

113. We will accept, in part, the Filing Parties' First Compliance Filing as it relates to their proposed provisions governing the establishment and operation of Independent Transmission Companies. First, we will require the Filing Parties to modify their provisions allowing the inclusion of Independent Transmission Company projects in the ISO-NE RTO's Regional System Plan. In the March 24 Order, we stated that in the event the ISO-NE RTO determines that any of the projects identified in the Independent Transmission Company plan would cause a material adverse impact on the ISO-NE RTO's facilities, the Independent Transmission Companies' plan cannot be incorporated into the Regional System Plan.[68] The Filing Parties propose to retain tariff language in Attachment M that would not explicitly preclude the ISO-NE RTO from accepting projects identified by the RTO that would cause a material adverse impact on the ISO-NE RTO's facilities to be included into the Regional System Plan. As a result, we will require the Filing Parties, in their compliance filing, to revise section 10.3.

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[66] *Id.* at P 154.

[67] *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Pubic Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,743-44 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,272 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and rev'd in part sub nom.*Transmission Access Policy Study Group v. FERC, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom.*, New York v. FERC, 535 U.S.1 (2002).

[68] March 24 Order at P 159.

114. In the March 24 Order, we required that section 10.05, in its entirety, be removed from the Transmission Operating Agreement and placed in the ISO-NE RTO OATT. The Filing Parties, however, have removed only certain portions of section 10.05 from the Transmission Operating Agreement. We will direct the Filing Parties to fully comply with this aspect of the March 24 Order. Specifically, the Filing Parties are required to remove section 10.05, in its entirety, from the Transmission Operating Agreement, make any conforming changes as may be required, and to re-file these provisions as revisions to the ISO-NE RTO OATT.

115. We will deny the Vermont Public Service Board's protest regarding the adequacy of the Filing Parties' explanation of the role to be played by an Independent Transmission Company in the development of Reliability Must Run costs. While the Vermont Public Service Board is concerned about the potential for abuse on the part of the Independent Transmission Company, we note that it will be the ISO-NE RTO, not the Independent Transmission Company, which will have the ultimate authority over the development of Reliability Must Run costs.

## J. Tariff Administration and Design

### 1. The March 24 Order

116. The March 24 Order found that Filing Parties' RTO formation proposal met the Commission's RTO tariff administration and design requirements, subject to the following conditions: (i) revised procedures making clear that the Filing Parties' Alternative Dispute Resolution provisions will be available to all market participants on an equal basis; and (ii) revisions to the Filing Parties' maintenance rules making clear that generators who are not required to meet Installed Capacity obligations, i.e., generators whose units are classified as "de-listed" resources, must not be required to adhere to the same maintenance rules that apply to generators who are required to meet these obligations, i.e., generators whose units are classified as "listed" resources.

### 2. Compliance Filing

117. The Filing Parties assert that in their First Compliance Filing they have complied with each of the tariff administration and design requirements set forth by the Commission in the March 24 Order. With respect to the Commission's requirement that generators not required to meet Installed Capacity obligations not be required to adhere to maintenance rules applicable to the Installed Capacity market, the Filing

Parties state that they have revised section 8.3.3 of Market Rule 1 by adding a new section 8.3.3.1 ("De-listed Resource Outage Provision").[69]

### 3. Responsive Pleadings

118. Calpine Eastern, et al. take issue with the Filing Parties' proposed revisions to section 8.3.3. Calpine Eastern, et al. assert that the Filing Parties' proposed revisions ignore the fundamental principle underlying the Commission's directive in the March 24 Order, i.e., that a capacity resource obligation should only arise when a unit owner enters into an explicit commercial transaction for the sale of capacity. Calpine Eastern, *et al.* argue that the Filing Parties' proposed revision, by contrast, provides only that de-listed resources be treated as a separate class of resources entitled to slightly greater deference when determining whether maintenance requests will be approved, while essentially imposing the same obligation on such resources as on a listed Installed Capacity resource. In addition, Calpine Eastern, et al. assert that the Filing Parties' proposed revisions to section 8.3.3 do not contain adequate compensation provisions for resources that are subject to forced re-listing.

119. The New England Consumer Owned Entities also object to the Filing Parties' proposed revisions to section 8.3.3 of Market Rule 1. The New England Consumer Owner Entities argue that the Filing Parties' proposed revisions exceed the scope of the requirements addressed by the Commission in the March 24 Order. Specifically, the New England Consumer Owned Entities argue that the Filing Parties' proposed revisions would not have the effect of releasing non-Installed Capacity resources from Installed Capacity maintenance obligations (as the March 24 Order requires), but, in addition, would grant these non-Installed Capacity resources certain undue preferences vis a vis Installed Capacity resources.[70] The New England Consumer Owned Entities submit these revisions, if approved, would create unjustified incentives and rewards for generators who know their resources are needed to meet reliability needs.

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[69] The proposed provision states, among other things, that "[o]utage requests for De-Listed Resources shall have precedence over the outage requests or schedules of listed [Unforced Capacity] Resources and shall normally be granted."

[70] The New England Consumer Owner Entities point out, for example, that under the Filing Parties' proposed provision, outage requests for De-Listed Resources would be given precedence over the outage requests or schedules of listed Uninstalled Capacity resources and will normally be granted.

#### 4. Commission Finding

120. We will reject the Filing Parties' First Compliance Filing as it relates to the tariff administration and design requirements of the March 24 Order. We agree with Calpine Eastern, et al. and the New England Consumer Owned Entities that the Filing Parties' proposed revision to section 8.3.3.1 does not satisfy our requirement that de-listed resources not be required to meet the same maintenance standards as listed resources. However, we reject the Calpine Eastern, et al. argument that section 8.3.3.1 of Market Rule 1 does not contain adequate compensation for resources that re-listed. We find that the Filing Parties' Market Rule 1 provisions provide appropriate compensation to resources that are re-listed.

121. Under Market Rule 1, a re-listed resource is eligible to receive the Uninstalled Capacity clearing price used for load shifting in the obligation month for which the resource has been re-listed, plus any additional reasonably incurred maintenance and opportunity costs associated with re-scheduling the outage and becoming an Installed Capacity resource. We find that these provisions are reasonable. Accordingly, we direct the Filing Parties, in a compliance filing to be made within 30 days following the issuance of this order, to revise section 8.3.3.1 to comply with the requirement for de-listed resources, as discussed herein.

### K. Billing Procedures

#### 1. March 24 Order

122. In the March 24 Order, we required the Filing Parties to revise section 3.10 of the Transmission Operating Agreement to eliminate provisions for separate billing for transmission and market services to avoid an unwarranted "me first" call on the ISO-NE RTO's receivables and to avoid spreading the potential costs unto all other market participants in the form of increased financial assurances.[71]

#### 2. Requests for Rehearing

123. On rehearing, the Transmission Owners' argue that the Commission erred in the March 24 Order in finding that the Filing Parties' proposed separation of revenues under section 3.10 of the Transmission Operating Agreement should be rejected. The

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[71] March 24 Order at P 119.

Transmission Owners argue that section 3.10, as proposed, appropriately recognized the need to separate these revenues in order to ensure that revenues would remain unencumbered property of the Transmission Owners, such that they would be available to provide an appropriate and acceptable level of security to lenders and equity investors in Transmission Owner's transmission businesses.

124. The Transmission Owners argue that the revenues received for the provision of transmission service using their facilities rightfully belong to the Transmission Owners. Nonetheless, the Transmission Owners argue that the March 24 Order suggests that the Transmission Owners' interests in retaining rights to their accounts receivable for transmission service could be outweighed by the potential costs that could be borne by all other market participants in the form of increased financial assurances.

### 3. Compliance Filing and Responsive Pleadings

125. The Filing Parties, in their First Compliance Filing, propose to eliminate section 3.10 of the Transmission Operating Agreement, pending stakeholder consideration of a revised provision. The Filing Parties state that they are developing alternative billing and invoicing provisions to replace the as-filed version of this provision, which they intend to submit to a stakeholder review process. The Filing Parties state that a revised section 3.10 will be filed with the Commission following the completion of this stakeholder process.

126. The New England Consumer Owned Entities urge that any finding that the ISO-NE RTO meets the operating authority requirements of Order No. 2000 must remain conditional until a revised section 3.10 is filed, reviewed and accepted.

### 4. Commission Finding

127. We will deny the Transmission Owners' rehearing request as it relates to our finding, in the March 24 Order, regarding the ISO-NE RTO's billing procedures. As we determined in the March 24 Order, the Filing Parties proposed a dual billing system that could lead to increased financial assurance of certain market participants. In fact, in their answer, the Filing Parties acknowledged that the proposed dual billing system may potentially lead to increased financial assurance of certain market participants.

128. We find that in the initial stages of RTO development in the New England Region a billing system that could potentially lead to increased financial assurances for certain market participants, could dampen participation in the marketplace. This is inconsistent with our goal to increase participation in RTO markets. Additionally, in the First Compliance Filing, the Filing Parties deleted section 3.10 of the Transmission Operating Agreement consistent with the Commission's directive. Further, given the fact that the Filing Parties are developing new billing provisions utilizing the stakeholder

mechanisms, we would not oppose a dual billing system to provide additional financial assurance to the Transmission Owners as long as such billing practice does not result in additional credit requirements being imposed on market participants.

129. Finally, we will deny the protest argument raised by the New England Consumer Owned Entities regarding the Filing Parties' compliance with all aspects of our RTO operational control requirements as they relate to section 3.10. Beyond the guidance provided herein, we need not further condition the start-up of the ISO-NE RTO.

### L. Facility Ratings

130. In the March 24 Order, we required the Filing Parties to revise section 3.06(v) of the Transmission Operating Agreement to provide for collaboration between the ISO-NE RTO and Transmission Owners in the establishment of transmission facility ratings. The Transmission Owners seek clarification that the March 24 Order only requires the Transmission Owners to collaborate with the ISO-NE RTO on the establishment of transmission facility ratings, but does not require the Transmission Owners to transfer the ultimate authority over these matters to the ISO-NE RTO. The Transmission Owners assert, in this regard, that their proposed division of functions as between ISO-NE and the Transmission Owners and that their proposed approach for establishing ratings were consistent with the policy set forth in Order No. 2000.

131. We will grant the requested clarification. The March 24 Order did not require the Transmission Owners to transfer the ultimate authority for establishing transmission facility ratings to the ISO-NE RTO. Rather, we are requiring cooperation and consultation between the Transmission Owners and the ISO-NE RTO, as may be appropriate.

### M. Transmission Outage Scheduling

#### 1. The March 24 Order

132. In the March 24 Order, we rejected proposed section 3.08 of the Transmission Operating Agreement which addressed the repair and maintenance of transmission facilities. As proposed, section 3.08 would have allocated certain responsibilities over transmission outage scheduling to the ISO-NE RTO, while allocating other responsibilities to the Transmission Owners. In the March 24 Order, we held that the ISO-NE RTO should be given the ultimate authority over these matters, in a provision to be included either in the ISO-NE RTO OATT, or in Market Rule 1.[72] We also required

the Filing Parties to include language in Market Rule 1 making it clear that all proposed outages must be considered together by the ISO-NE RTO when it decides to accept a proposed Transmission Owner outage plan. We found that by considering all proposed outages (both transmission and generation), the ISO-NE RTO would be able to ensure that the system impact attributable to these outages would be minimized in a way that would reduce congestion and promote market efficiency.[73]

### 2. Requests for Rehearing

133. On rehearing, the Transmission Owners assert that the Commission erred in the March 24 Order in not accepting section 3.08, as proposed. The Transmission Owners argue that while Order No. 2000 does not require the Transmission Owners to provide the ISO-NE RTO with any authority to cancel or reschedule outages based on economic or reliability market considerations, the Transmission Owners have been willing to voluntarily provide defined and limited authority for economic or market-based rescheduling of outages to the ISO-NE RTO. The Transmission Owners assert that when the Commission rejected this balance in the March 24 Order, it did so on a basis not required by Order No. 2000.

134. The Transmission Owners further argue that the Commission erred in requiring that transmission facility outage provisions be removed from the Transmission Operating Agreement and transferred to the ISO-NE RTO OATT, or to Market Rule 1. The Transmission Owners submit that keeping these provisions in the Transmission Operating Agreement, as proposed, would ensure that the terms and conditions governing the ability of the Transmission Owners to maintain their own assets could only be changed with their consent. The Transmission Owners urge that if the Commission does not grant rehearing on this issue, it should clarify that transmission outage provisions should be transferred from the Transmission Operating Agreement to the ISO-NE RTO OATT, and should not be included in Market Rule 1.

135. The Transmission Owners also argue that there are numerous protections already in place that would grant the Commission and market monitors sufficient authority to ensure that the Transmission Owners would not schedule outages in a manner to manipulate the market for Firm Transmission Rights.

136. In addition, the Transmission Owners argue that permitting the ISO-NE RTO to exercise unlimited authority to reschedule transmission maintenance outages for

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[72] *Id.* at P 120.

[73] *Id.* at P 121.

economic considerations would limit the ability of the Transmission Owners to develop mechanisms that provide the appropriate incentives for operational and planning actions designed to improve market outcomes.

### 3. Compliance Filing

137. The Filing Parties state that they have removed section 3.08 of the Transmission Operating Agreement and transferred the substance of this provision to new Appendix G to Market Rule 1 as it relates to the ISO-NE RTO's authority to modify outage schedules. The Filing Parties also state that Appendix G reflects the Commission's ruling, in the March 24 Order, that the ISO-NE RTO be given the ultimate authority to modify outage schedules.

### 4. Responsive Pleadings

138. Duke Energy, the New England Consumer Owned Entities, and the Vermont Public Service Board argue that Appendix G, as proposed, continues to limit the authority of the ISO-NE RTO, contrary to the requirements of the March 24 Order. In particular, these intervenors point out that under the Filing Parties' proposed revision, the ISO-NE RTO would be given no authority to require the rescheduling of an outage based on any estimated or actual impacts on congestion or Reliability Must Run costs in financial, day-ahead markets, whether or not such outage had previously been scheduled. These intervenors argue that Appendix G should expressly state that the ISO-NE RTO shall have the ultimate authority to modify outage schedules based on either reliability or economic considerations.

139. Duke Energy, the Vermont Public Service Board and Calpine Eastern, et al. also argue that the First Compliance Filing fails to include language in Market Rule 1 making clear that all proposed outages be considered together by the ISO-NE RTO when it decides to accept a proposed Transmission Owner outage plan.

### 5. Commission Finding

140. We will deny the Transmission Owners' rehearing request with regard to the ISO-NE RTO's ultimate authority to reschedule transmission outages for economic or reliability considerations. We agree with the Transmission Owners that the Commission's reasoning in giving the ISO-NE RTO ultimate authority to reschedule outages for economic or reliability considerations was not based on our directives in Order No. 2000. However, as we stated in the March 24 Order, allowing the Transmission Owners any influence in the rescheduling of transmission outages creates

an inherent conflict of interest, especially where the Transmission Owner also owns or controls generation resources or has load serving obligations.[74]

141. We also recognize the Transmission Owners' claim that there are sufficient checks in place to prevent the Transmission Owners from manipulating the Firm Transmission Rights market. However, the conflict of interest would still exist for any affiliate of a Transmission Owner that might purchase Firm Transmission Rights at auction, since any outage could be designed to favor the affiliate.[75] Our directive to provide the ISO-NE RTO with ultimate authority to reschedule transmission outages for economic or reliability considerations, combined with the oversight of the Market Monitoring Unit and the Commission, will adequately safeguard against Firm Transmission Rights market manipulation by Transmission Owners.

142. We will deny the Transmission Owners' request for rehearing regarding the Transmission Owners' ability to develop mechanisms that provide appropriate incentives for operational and planning actions designed to improve market outcomes. The impact of the transmission outage scheduling provision on the Transmission Owners will be minimized due to the infrequency of outage schedule modifications and is otherwise outweighed by the need to eliminate the inherent conflict of interest that Transmission Owners would have in scheduling transmission outages.

143. With respect to protesters' concerns, we agree that Appendix G of Market Rule 1, as filed, does not include language requiring the ISO-NE RTO to consider all proposed transmission and generation outages together in accepting a proposed transmission owner outage plan, and we will require the ISO-NE RTO to correct this error in a filing within 90 days of issuance of this order. We also agree with the protestors that Market Rule 1 fails to provide the ISO-NE RTO with the authority to require the rescheduling of an outage based on any estimated or actual impacts on congestion or Reliability Must Run costs in financial, day-ahead markets, whether or not such outage has previously been scheduled. Market Rule 1 must contain plainly stated language that the ISO-NE RTO shall have the ultimate authority to modify outage schedules based on either reliability or economic considerations. This will provide the ISO-NE RTO adequate authority to ensure that the system impact caused by such outages will be minimized in a way that

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[74] *Id.* at P 120.

[75] *See, e.g.*, Exelon Corporation, *et al.*, 97 FERC ¶ 61,009 (2001); PJM Interconnection, L.L.C., *et al.*, 97 FERC ¶ 61,319 (2001).

reduces congestion and promotes market efficiency. We will require the Filing Parties to revise Appendix G of Market Rule 1 to comply with this directive.

144. We will also deny the Transmission Owners' request for rehearing and clarification regarding placement of provisions regarding this authority. In fact, transmission facility outage provisions must be placed in the ISO-NE RTO OATT or Market Rule 1. We recognize the Transmission Owners' concern that keeping the outage scheduling provision in the Transmission Operating Agreement would ensure that only the Transmission Owners could alter the provisions. However, placement in the OATT, or Market Rule 1, will ensure that authority over these matters will be given to the ISO-NE RTO and thus made subject to the stakeholder input process, in which the Transmission Owners may participate. Moreover, the ISO-NE RTO must have the ultimate and unlimited authority to modify outage schedules because of reliability or economic considerations. As such, we will require the Filing Parties to revise Appendix G of Market Rule 1 to comply with this directive.

## N. System Planning and Expansion

### 1. The March 24 Order

145. The March 24 Order found that the Filing Parties' proposed system planning and expansion procedures met the Commission's RTO formation requirements, subject to the following four conditions: (i) modification of the provision relating to the Request for Alternative Proposals to expand system transmission capacity, consistent with our rulings in a related proceeding addressing the procedures available to the ISO-NE when no viable solutions have been proposed to meet a near-term reliability need;[76] (ii) re-filing of the Filing Parties' proposed system planning and expansion provisions as revisions to the planning sections of the ISO-NE RTO OATT;[77] (iii) clarification that at the end of the ISO-NE RTO planning process, if there is no agreement to build a given project, a filing must be made by the ISO-NE RTO, including a recommendation as to whether it would be appropriate for the Commission to require an enlargement of facilities under the FPA or to take other steps; and (iv) clarification of the standards and procedures to be followed by the ISO-NE RTO to promote market efficiency upgrades, identify cost-

[76] *See* ISO New England Inc., 106 FERC ¶ 61,190 (2004) (Gap RFP Order).

[77] We found that with the exception of those provisions that affect only (or predominantly) the rights and responsibilities of the Filing Parties alone, *i.e.*, sections 6 and 7 of schedule 3.09(a), provisions addressing system planning and expansion do not belong in the Transmission Operating Agreement, given the effect that these provisions may have on market participants as a whole.

effective solutions, and allocate any Financial Transmission Rights or Auction Revenue Rights that would result from the construction of new facilities.

### 2. Requests for Rehearing

146. Rehearing of the March 24 Order, with respect to the Commission's findings regarding transmission planning and expansion matters, was sought by the Transmission Owners, PSEG, and the New England Consumer Owned Entities. The following Reserved Issues are identified in the Settlement Agreement.

147. First, PSEG asserts as error the Commission's failure in the March 24 Order to prescribe an appropriate amount of time in the planning process during which the market can respond to a planning need identified by the ISO-NE RTO. PSEG argues that this time allowance is necessary in order to create a level playing field for all responses to transmission congestion. In addition, PSEG argues that the ISO-NE RTO should be required to publish its needs assessment with a sufficient amount of time allowed for a market response, and the ISO-NE RTO should be required to withhold its cost-benefit analysis until the "market window" has closed. PSEG claims that such a policy is necessary because competing merchant developers would otherwise have difficulty in obtaining financing for their proposed projects to the extent they would be required to compete against estimates that may, by definition, be less than accurate.

148. Finally, PSEG asserts as error the Commission's failure in the March 24 Order to include a sensible scope change process in the event of cost overruns during the course of a project. PSEG argues that without an efficient mechanism to change the scope of a project, the economic expansion process could lead to the development of upgrades that cost more than the congestion they eliminate.

149. The New England Consumer Owned Entities claim that the March 24 Order failed to approve necessary enforcement mechanisms for the commitment to construct new and upgraded transmission facilities. The New England Consumer Owned Entities also assert that the Filing Parties should be required to provide market participants the opportunity to support grid expansion by allowing third-party buy-in for capital contribution upgrades identified in the ISO-NE RTO plan up to their load ratio shares.[78]

[78] The New England Consumer Owned Entities argue that the benefits attributable to such participation would only be realized if third parties are permitted to participate in such projects, whether through contributions of capital or joint construction and/or ownership with Transmission Owners. The New England Consumer Owned Entities assert that smaller entities, such as municipal systems, while not in a position to fund and

(continued...)

150. The New England Consumer Owned Entities also assert as error the Commission's determination not to adopt revisions to the Filing Parties' proposed system planning and expansion procedures that would require Transmission Owners to: (i) jointly develop, along with the ISO-NE RTO, a detailed implementation plan that would include schedules and benchmarks leading to the completion of planned facilities; (ii) report to the ISO-NE RTO at least quarterly, or as otherwise agreed, on their progress toward achieving the schedules and benchmarks included in the implementation plan; and (iii) submit to the ISO-NE RTO their plan to cure delays, where progress on significant schedules and benchmarks are not being achieved. In addition, the New England Consumer Owned Entities argue that in the event the ISO-NE RTO determines that a Participating Transmission Owner is not using its "best efforts" to complete a given project, the ISO-NE RTO should be authorized, in this instance, to request that other entities be permitted to submit proposals to either build the planned project or to otherwise meet the identified expansion need.

151. The Transmission Owners, on rehearing, object to the Commission's requirement that the Filing Parties' proposed system planning and expansions provisions be re-filed as revisions to the ISO-NE RTO OATT. The Transmission Owners argue these provisions exclusively concern terms and conditions related to the unique rights and obligations of the Transmission Owners. The Transmission Owners further assert that comparable provisions were accepted by the Commission for inclusion in the transmission operating agreement applicable to the Midwest ISO.[79]

### 3. Compliance Filing

152. In their First Compliance Filing, the Filing Parties state that they have re-filed their proposed system planning and expansion provisions, with the exception of sections 6 and 7 of schedule 3.09, as a revision to planning provisions of the ISO-NE RTO OATT. The Filing Parties also state that the remaining provisions of schedule 3.09 have been modified to reflect the Commission's directive that the ISO-NE RTO is required to file a report if there is no agreement to build a given project and to eliminate the provisions that could release a Participating Transmission Owner from the obligation to build based on the non-binding written opinion of the chair of a state siting board.

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construct their own projects, would nonetheless bring important consumer benefits and capital to such projects.

[79] *See* Appendix B to the Midwest ISO Transmission Owners' Agreement.

153. The Filing Parties state that in order to identify market efficiency upgrades and assess cost effective solutions, as required by the March 24 Order, they have developed a new planning procedure proposal, but that these new planning procedures have yet to receive NEPOOL stakeholder approval.[80] Accordingly, the Filing Parties submit these proposed procedures for informational purposes only. The Filing Parties state that these procedures include: (i) standards for identifying Reliability Transmission Upgrades; (ii) standards for identifying Market Efficiency Transmission Upgrades, including use of a "Base Economic Evaluation Model" for determining the net present value of bulk power system resource costs and analysis of other data to calculate the net cost load with and without the transmission upgrade; and (iii) procedures for identifying Reliability and Market Efficiency Transmission Upgrades.

154. The Filing Parties state that the revised tariff sheets included in their First Compliance Filing also include modifications to section 48.5 of the ISO-NE RTO OATT, regarding Requests for Alternative Proposals. The Filing Parties state that, as required by the March 24 Order, these provisions have been conformed to the requirements of the GAP RFP Order, including a new provision allowing for the filing with the Commission of proposed Requests for Alternative Proposals at least 60 days in advance of issuance, and the filing of jurisdictional contracts or funding mechanisms and the informational filing of other contracts.

### 4. <u>Responsive Pleadings</u>

155. The New England Consumer Owned Entities argue that the First Compliance Filing fails to explain how the ISO-NE RTO will allocate any financial rights or Auction Revenue Rights that would result from the construction of new facilities. In addition, the New England Consumer Owner Entities take issue with the Filing Parties' apparent definition of "Market Efficiency Transmission Upgrades" as upgrades designed primarily to provide a net reduction in total production cost to supply the system load. The New England Consumer Owner Entities point out that while it is appropriate to consider the "net reduction" amount, this analysis should include a consideration (along with all net cost factors) all net economic benefits associated with a potential system upgrade.

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[80] In comments submitted in response to the Filing Parties' First Compliance Filing, NEPOOL states that at a June 30, 2004 meeting of NEPOOL's Participants Committee, a vote was taken in support of the Filing Parties' proposed planning procedures.

156. In addition, NECPUC claims that the Filing Parties have failed to remove all provisions of section 3.09 from the Transmission Operating Agreement. NECPUC argues that section 3.09 (b), which deals with dispute resolution, should have been moved to the ISO-NE RTO OATT.

### 5. Commission Finding

157. We will grant rehearing, in part, and deny rehearing, in part, of the March 24 Order, as it relates to our RTO system planning and expansion requirements. First, we will deny rehearing regarding the New England Consumer Owned Entities' argument that the March 24 Order erred by not directing the Filing Parties to adopt the New England Consumer Owned Entities' proposals for third-party participation. Section 48 of the initial ISO-NE RTO OATT filed states in part:

> The purpose of the Regional System Plan is to identify system reliability and market efficiency needs and types of resources that may satisfy such needs so that Market Participants may provide efficient market solutions (e.g., demand-side projects, distributed generation and/or merchant transmission) to identified needs.

158. There are no provisions that prohibit a third-party from providing a solution to an identified need. Thus, the ISO-NE RTO regional planning process provides the opportunity for third party participation in transmission projects.

159. We also disagree that our rejection of the New England Consumer Owned Entities' proposal to require that third parties be given the opportunity to make capital contributions on individual transmission projects or become joint owners is a retreat from our previous recognition of third-party participation, or is otherwise inconsistent with our previous rulings regarding third-party participation. The Commission has consistently found that our long term competitive goals are better served by RTO expansion plans that allow for third-party participation and allow for the construction of merchant projects outside the plan.[81] However, we have not required Transmission Owners to provide consumer-owned entities, or other load serving entities, an equity share in every individual transmission project or require that third parties must be given the opportunity to make capital contributions in individual transmission projects.

160. With respect to the New England Consumer Owned Entities' assertion that the Commission erred by not adopting certain enforcement mechanisms applicable to a Participating Transmission Owners' obligation to build, we disagree that this obligation

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[81] PJM Interconnection, L.L.C., 96 FERC ¶ 61,061 at 61,241 (2001).

can be influenced by (or avoided by) the Transmission Owner's considerations of its own interests in a given project. In addition, consistent with the Commission's requirement to file a report in the event there is no agreement to build a given project, the Filing Parties have committed to file reports consistent with the March 24 Order.[82] Therefore, we will deny the New England Consumer Owner Entities request for rehearing.

161. With respect to the arguments raised on rehearing by PSEG and the New England Consumer Owned Entities regarding cost overruns, posting of the needs assessment prior to the market window, and the timing of the cost-benefits analysis, we agree that these issues should be addressed in the Regional System Plan. However, it would be premature to consider the merits of such proposals at this time. The Filing Parties are working through the stakeholder process to develop revisions to the Regional System Plan. We will review these issues once the Filing Parties submit their Regional System Plan.

162. We find the Filing Parties have transferred the relevant portions of schedule 3.09(a) (Planning and Expansion) to the Transmission Operating Agreement as directed in the March 24 Order. The Commission will clarify that footnote 84 did not direct that section 3.09 of the Transmission Operating Agreement should be transferred to the RTO-NE OATT. As we have previously indicated, all of section 3.09 and sections 6 and 7 of schedule 3.09(a) concern general references to previously adopted planning procedures and, as such, should remain in the Transmission Operating Agreement.

163. As noted above, we required the Filing Parties to clarify certain of the standards and procedures that will be followed by the ISO-NE RTO in developing and implementing its Regional System Plan. In response, the Filing Parties explain that in order to identify market efficiency upgrades and to assess cost-effective solutions, a variety of new planning procedures were developed. The Filing Parties also explain,

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[82] ISO-NE RTO OATT, section 48.6 (Obligation of Participating Transmission Owners to Build) states in relevant part:

> In the event that a [Participating Transmission Owner] PTO does not construct or indicates in writing that it does it not intend to construct a transmission upgrade included in the [Regional System Plan] RSP; or demonstrates that it has failed (after making a good faith effort) to obtain necessary approvals or property rights under applicable law, ISO-NE shall promptly file with the Commission a report on the results the Transmission Owner responsible for the planning, design or construction of such transmission upgrade, in order to permit the Commission to determine what action, if any, it should take. Similar provisions are proposed in schedule 3.09(a) (Planning and Expansion) of the Transmission Operating Agreement.

however, that these proposed planning procedures are addressed in their First Compliance Filing in outline form only, i.e., not in the form of proposed tariff revisions that could be accepted for filing. The Filing Parties state that they were unable to comply with this aspect of the March Order 24 Order due to their inability to obtain stakeholder support for these proposed changes.[83] We find that the Filing Parties have failed to provide the clarifications and proposed changes contemplated by the March 24 Order. Accordingly, we will require the Filing Parties to include, in their compliance filing on, or before, 60 days following the issuance of this order, all tariff revisions required to fully satisfy this aspect of the March 24 Order.

### O. Market Monitoring

#### 1. March 24 Order

164. In the March 24 Order, we held that the Filing Parties' RTO formation proposal met our RTO market monitoring requirements, subject to certain conditions relating to the ISO-NE RTO's market information policy and the imposition of penalties.84 With respect to the ISO-NE RTO's information policy, we required the Filing Parties to submit a filing within 30 days of the date of our order addressing PJM's planned revision of its information policy. In their filing, we required the Filing Parties to address any variations that may be required in that policy as it would apply to the ISO-NE RTO.

165. We also required the Filing Parties to address the Commission's November 17, 2003 order amending all market-based rate tariffs and authorizations to ensure compliance with six Market Behavior Rules.[85] We noted that in MBR Tariff Order, we had held that it was appropriate to authorize Market Monitoring Units to enforce certain ISO/RTO tariff matters concerning market behavior for matters that objectively identifiable and for which penalties are clearly set forth in the tariff. We further noted that because the Filing Parties' RTO formation proposal in this proceeding was filed prior

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[83] Among other things, the Filing Parties' outline fails to discuss how the ISO-NE RTO will allocate Firm Transmission Rights or Auction Revenue Rights attributable to the construction of new facilities.

[84] March 24 Order at P 187.

[85] Investigation of Terms and Conditions of Public Utility Market-Based Rate Authorizations, 105 FERC ¶ 61,218 (2003) (MBR Tariff Order), *order on rehearing*, 107 FERC ¶ 61,175 (2004).

to the issuance of the MBR Tariff Order, the Filing Parties had not addressed the extent to which their RTO formation proposal satisfied the requirements of the MBR Tariff Order. Accordingly, we directed the Filing Parties to demonstrate that the ISO-NE RTO's market rules, including any penalty provisions, comply with MBR Tariff Order.

### 2. Requests for Rehearing

166. On rehearing, the New England Consumer Owned Entities assert as error our determination not to approve independent, outside guidelines applicable to the ISO-NE RTO itself. The New England Consumer Owned Entities also assert that the Commission erred in the March 24 Order in rejecting the New England Consumer Owned Entities' proposal to require the ISO-NE RTO to release actual bid and offer data, preferably on the day following the trading day, but in no event more than a week after the fact.

### 3. Compliance Filing

167. In their First Compliance Filing, the Filing Parties state the ISO-NE RTO's market monitoring and sanctioning authority is consistent with the Commission's directive in the MBR Tariff Order. The Filing Parties state that, as such, they are proposing no revisions to these provisions at this time.

168. In their Second Compliance Filing, the Filing Parties state that their revised information policy proposal is based on PJM's recently revised information policy and the Commission's order accepting that revised policy.[86] The Filing Parties note that under NEPOOL's existing Information Policy, ISO-NE is prohibited from disclosing confidential information to state commissions unless: (i) ISO-NE is authorized to release the confidential information by the Furnishing Participant; (ii) ISO-NE has been ordered to release the confidential information by an agency with jurisdiction over such matters; or (iii) such information is released to a state commission subject to an appropriate confidentiality order entered under such agency's procedures sufficient to preserve the confidential nature of the information submitted, and with advance notice to the Furnishing Participant.

169. The Filing Parties state that PJM's revised information policy establishes a more streamlined method for the release of confidential information to state commissions that would alleviate the need for those state commissions to invoke more time-consuming legal processes. The Filing Parties propose to implement this approach, subject to certain

[86] *See* PJM Interconnection, L.L.C., 107 FERC ¶ 61,322 (2004) (PJM Information Policy Order).

revisions appropriate for the New England region. First, the Filing Parties assert that PJM's provisions do not adequately define the scope of confidential material that could be provided to state utility commissions. To clarify the intended scope of the ISO-NE RTO information policy, the Filing Parties propose that while ISO-NE will provide access to non-public or confidential market data to state commissions to enable them to carry out their regulatory functions, other information, including but not limited to draft versions of reports and analyses, internal ISO-NE RTO documents not related to market data, and privileged legal information need not be provided.

### 4. Responsive Pleadings

170. In its comments on the Filing Parties' Second Compliance Filing, NECPUC states that it looks forward to working with the ISO-NE RTO as it proceeds to finalize its information policy proposal, in the context of an existing stakeholder proceeding. As that process moves forward, NECPUC states that it recognizes and accepts the fact that variations may be required as PJM's policy is tailored to fit the needs of the New England market.

171. NECPUC points out, in particular, that the information policy approved for PJM does not list with sufficient specificity the types of material that would be considered confidential. NECPUC states that having the Commission make a finding that certain types of market data are confidential and warrant protection from disclosure (e.g., bid data that is less than six months old, generator-specific outage information, or fuel supply and contract information), would allow at least some of the New England Commissions to sign a non-disclosure agreement to keep the information confidential. NECPUC asserts that a specific finding by the Commission would allow at least some of the state commissions, based on that finding, to protect the information without requiring the state commission to issue its own protective order.

172. NECPUC also asserts that the PJM provision relating to the destruction or return of confidential material should be modified by adding "unless such actions are inconsistent with or prohibited by applicable state law in which case the material will continue to be treated as confidential. Finally, NECPUC states that the information policy process approved by the Commission should provide for the ISO-NE RTO to file with the authorized commission a copy of the document provided with redactions of the confidential material if it is practical and feasible to create a redacted document.

### 5. Commission Finding

173. We will deny the New England Consumer Owned Entities' rehearing request regarding the need to review and monitor the acts and/or omissions of the ISO-NE RTO. Order No. 2000 does not require an independent, outside review of the operation of the

RTO. In the March 24 Order, moreover, we stated that the Commission is both able and prepared to fulfill this role.

174. We will also deny rehearing of the March 24 Order regarding the market information transparency issues raised by the New England Consumer Owned Entities. While we agree with the New England Consumer Owned Entities that market participants need access to bid and offer data to permit parties to monitor the market, we find that such data should not be released immediately after bidding, i.e., after only one day or even one week after bidding. In fact, there would be a risk of collusion presented by such disclosure. The Commission has previously required ISO-NE to disclose individual bid data with a six-month time lag to market participants and we will not require the ISO-NE RTO to disclose this data prior to that time.[87]

175. As we stated in *California Independent System Operator Corporation*,[88] the release of bid information with less than six months' delay does not protect the commercial sensitivity of the data.[89] Further, the ISO-NE RTO Market Monitoring Units will: (i) perform independent evaluations and prepare annual and ad hoc reports on the overall competitiveness and efficiency of the New England Markets; (ii) conduct evaluations and prepare reports on its own initiative or at the request of others; (iii) provide information to be directly included in the monthly market updates that are provided at the meetings of the Participants Committee; and (iv) produce weekly, quarterly and annual reports regarding the New England Markets.[90] We find that the ISO-NE RTO's market monitoring provisions provide market transparency and appropriate access to interested market participants.

176. We will accept, in part, and reject, in part, the Filing Parties' compliance filings as they relate to market monitoring matters. First, we will accept the Filing Parties' Second Compliance Filing, subject to condition. Upon review, we find that the proposed changes to the ISO-NE RTO information policy, as outlined by Filing Parties in their Second Compliance Filing, are generally consistent with the information policy approved

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[87] *See* NSTAR Services Company v. New England Power Pool, *et al.*, 92 FERC ¶ 61,065 (2000).

[88] 90 FERC ¶ 61,316 at 62,047 (2000).

[89] *See also* PJM Interconnection, L.L.C., 88 FERC ¶ 61,274 (1999).

[90] *See* section 9 of the Participants Agreement and Market Rule 1.

for PJM.[91] We also agree with NECPUC that that certain variations to this policy may be appropriate as it applies to the New England market. However, we will not prejudge these issues here in the absence of a specific proposal and prior to the conclusion of the existing stakeholder process. However, we will require the Filing Parties to submit tariff sheets reflecting their proposed changes to the PJM information policy no later than 60 days following the date of this order.

177. With respect to market monitoring matters, we are not satisfied that the Filing Parties' proposed market monitoring provisions, as included in their initial RTO formation proposal in this proceeding, fully comply with the requirements of the MBR Tariff Order. In the MBR Tariff Order, we stated that Market Monitoring Units, existing under an ISO/RTO framework, serve an important policing function, but that these Market Monitoring Units should be permitted to enforce certain ISO/RTO tariff requirements, if (and only if) those tariff requirements are: (i) expressly set forth in the tariff; (ii) involve objectively-identifiable behavior; and (iii) do not subject market participants to sanctions, or other consequences, other than those expressly approved by the Commission and set forth in the tariff. The ISO-NE RTO Tariff imposes penalty charges on market power abuses that cannot be dealt with prospectively, such as physical withholding that can only be identified *ex post* through investigations and/or audits. In cases dealing with physical or economic withholding, it appears that evaluation of the conduct would involve subjective judgments. The Commission's Market Behavior Rules establish that this type of inquiry is to be conducted by the Commission, not by the market monitor.

178. The market monitoring provisions included in the Filing Parties' RTO proposal (in Market Rule 1, at Attachments A and B), however, do not appear to fully satisfy these requirements, particularly the requirement that the enforcement authorizations set forth in these provisions identify objectively identifiable behavior. Rather, it appears that at least some of the conduct that could be sanctioned under the Market Rule 1 provisions at issue may involve subjective evaluations. For example, section III.B.3.3 (addressing "Inaccurate Bid or Operating Information") allows for sanctions for an understatement, or for a maximum limit, when the market participant "knew or should have known" that the resource's limit was greater. Similarly, sanctions are permitted, under section III. B.3.2.3, when a market participant misrepresents operating conditions under those circumstances where the market participant "knew or should have known" the statement to be "materially inaccurate."[92]

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[91] *See* PJM Information Policy Order at P 11.

[92] *See also* sections III.B.3.2.2 and III.B.3.2.4.

179. In the MBR Tariff Order, however, we stated that subjective inquiries of this sort are to be conducted by the Commission, not by a Market Monitoring Unit. Moreover, the standard set forth in the Filing Parties' proposed market monitoring provisions, i.e., the "knew or should have known" standard,[93] is inconsistent with the standard adopted by the Commission in the MBR Tariff Order with respect to Market Behavior Rule 3.[94] Specifically, Market Behavior Rule 3 prohibits a market participant from providing inaccurate information to market monitors unless "due diligence" is exercised. In addition, the market monitor, under section III.B.3.2.6, is given virtually unfettered discretion in determining what are "good faith" excuses regarding the availability of resources. While this provision delineates some excuses, such excuses "are not limited to" those set forth in the tariff. Likewise, in the tariff's "Interpretation" section, the market monitor is given discretion to determine the effect of a market participant's investigation of a failure of a resource to perform.[95]

180. We are also concerned by the extent of the discretion that may be exercised by the market monitor under Market Rule 1 at Attachment A. While the types of conduct subject to mitigation as described in Appendix A are appropriate, for example, in order to be consistent with the guidance provided in recent orders, including the Midwest ISO order,[96] we do not believe that the ISO-NE RTO has defined some of the types of conduct subject to mitigation in a manner that includes sufficiently clear, objectively quantifiable standards. We believe that in the definition of physical withholding, III.A.4.22, actions that constitute "unjustified deratings" should be defined. In III.A.4.3, in which the

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[93] Although this standard is defined at section III.B.3.7.2, the definition requires subjective discretion of the type that the Commission has retained for itself.

[94] Market Behavior Rule 3 states as follows:

> Seller will provide accurate and factual information and not submit false or misleading information, or omit material information, in any communication with the Commission, Commission-approved market monitors, Commission-approved regional transmission organizations, or Commission-approved independent system operators, or jurisdictional transmission providers, unless Seller exercised due diligence to prevent such occurrences.

[95] *See* section III.B.3.7.2 ("the [ISO-NE RTO] may consider a Market Participant's efforts (or lack of efforts) to investigate a Resource's failure to perform . . . .")

[96] Midwest Independent Transmission System Operator, Inc., 108 FERC ¶ 61,163 (2004).

ISO-NE RTO investigates physical withholding according to the process in III.A.3, the concepts of "conduct ... consistent with competitive behavior" and causing "a material effect on market clearing prices" should be made concrete. In III.A.5.4 the Filing Parties again should define what actions are "not consistent with competitive conduct." Also, in III.A.5.5.3, the Filing Parties should address what role "sensitivity analyses" or "such models and methods [the ISO-NE RTO] shall deem appropriate" will play in determining whether and what level of mitigation is to be applied.

181. The above-cited examples are not exhaustive, but merely illustrative of the type of discretion that the Commission will not allow a market monitor to exercise in imposing sanctions. Accordingly, we will direct the Filing Parties to modify their proposed market monitoring provisions, in a compliance filing to be made within 30 days of the date of this order, to ensure that these provisions are consistent with the Market Behavior Rule and do not vest the market monitor with discretion that the Commission has retained for itself. Rather the conduct subject to sanctions should be limited to conduct that is objectively identifiable.

182. Further, since all market-based rate sellers in the ISO-NE RTO's markets are subject to the Commission's Market Behavior Rules, we will require the Filing Parties to include the Commission's Market Behavior Rule 2, as applicable, in the ISO-NE RTO's tariff.[97] As we found in our order with respect to the California Independent System Operator's proposed tariff Amendment 55 by including such language in an RTO tariff, we can provide uniformity and clarity for market participants through consistent requirements. Of course, any potential violations of this provision of the tariff identified by the Marketing Monitoring Units should also be referred to the Commission. By including the language of the Commission's Market Behavior Rule 2 in the ISO-NE RTO's tariff, we will have further included a strong general anti-manipulation standard which, due to the uniformity of its language, in sellers' tariff's and other ISO/RTO tariffs, will help us develop clear rules and interpretations of the standard bringing additional certainty to the market.

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[97] In exercising its discretion to determine the appropriate remedy for violations of Market Behavior Rule 2, as added to the ISO-NE RTO's tariff, the Commission will apply the policies and principles set forth in the MBR Tariff Order, and subsequent relevant precedent.

## P. Indemnification

### 1. The March 24 Order

183. With respect to third party liabilities, the March 24 Order required the Filing Parties to conform Article IX of the Transmission Operating Agreement to the indemnification requirements advanced by the Transmission Owners, subject to the guidance and rationale set forth in our order.[98] First, we agreed with the Transmission Owners that the Transmission Operating Agreement should include an indemnification provision requiring the ISO-NE RTO and the Transmission Owners to be responsible for any third party liabilities attributable to their own respective acts or omissions. We held that each party should be responsible for its respective third-party liabilities, i.e., for those liabilities not addressed by the limitations on liability provisions in the ISO-NE RTO OATT (addressing liabilities as between the ISO-NE RTO and the ISO-NE RTO's OATT customers) or the Filing Parties' own side agreement concerning their respective second-party liability limitations as to each other.

184. As such, we rejected ISO-NE's proposed indemnification provisions. Under those provisions, as proposed, the ISO-NE RTO could not have been held liable to any Transmission Owner for any third-party claims filed against the Transmission Owner, even claims attributable to the ISO-NE RTO's own acts or omissions (except in cases involving the ISO-NE RTO's gross negligence or willful misconduct).

### 2. Requests for Rehearing

185. On rehearing, ISO-NE asserts that the Commission's acceptance of the Transmission Owners' indemnification proposal, in the March 24 Order, was premised on the Commission's erroneous assumption that the Transmission Owners' proposal would maintain the current allocation of risks for third party liabilities as between ISO-NE and the Transmission Owners under the ISO-NE/NEPOOL arrangements. ISO-NE argues that, in fact, it was ISO-NE's proposal that would have maintained these risks "as is" by refusing to carve out the Transmission Owners as a distinct sub-group deserving of its own indemnification provision. ISO-NE concludes that the Commission should reject the Transmission Owners' proposed indemnification provision in favor of the proposal advanced by ISO-NE.

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[98] March 24 Order at P 229.

186. In the alternative, ISO-NE asserts that should the Commission, on rehearing, reaffirm its decision to accept the Transmission Owners' reciprocal indemnification provisions, the Commission should ensure that the ISO-NE RTO will be able to recover the entirety of its indemnification costs, whether through insurance coverage or as pass-through to market participants. ISO-NE also requests that the Commission require that the ISO-NE RTO's negligence be a pre-condition to the ISO-NE RTO's obligation to indemnify the Transmission Owners for its third-party liabilities. Finally, ISO-NE asserts that the Commission should require the Transmission Owners to make representations and warranties about the condition of their facilities.

### 3. Compliance Filing

187. The Filing Parties point out in their First Compliance Filing that in their initial RTO formation proposal, herein, ISO-NE and the Transmission Owners advanced alternative provisions to be included in the Transmission Operating Agreement, at Article IX, regarding their respective liabilities to each other for third party liability claims.[99] Accordingly, in their First Compliance Filing, the Filing Parties state that the initial proposal advanced by ISO-NE (which we rejected in the March 24 Order) has been struck from the Transmission Operating Agreement, leaving in place those provisions, as sponsored by the Transmission Owners, which we accepted.

### 4. Commission Finding

188. We will accept the Filing Parties First Compliance Filing and deny rehearing with respect to our findings in the March 24 Order regarding the appropriate third-party liability provisions to be included in the Transmission Operating Agreement.

189. The fundamental issues raised by ISO-NE, on rehearing, are: (i) whether the ISO-NE RTO should be at risk for third-party claims attributable to its own acts or omissions, given its ability to pass these costs through to all market participants on a socialized basis, or (ii) whether these same liabilities, which are attributable to the ISO-NE RTO's own acts or omissions, should be allocated to the Transmission Owners alone.

190. In the March 24 Order, we correctly held that under the existing arrangements governing the rights and obligations of ISO-NE and NEPOOL, ISO-NE's third-party liability risks for ordinary negligence are allocated to all market participants by way of

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[99] Both proposals were included in bracketed form in the Filing Parties' initial submissions.

NEPOOL.[100] We noted that while ISO-NE now proposed to allocate these same risks to the Transmission Owners alone, ISO-NE had failed to provide any supportable justification for doing so. Accordingly, we accepted the Transmission Owners' proposed reciprocal indemnification provisions, consistent with ISO-NE's existing risks and liabilities under the ISO-NE/NEPOOL arrangements and our precedent, as established in *TRANSLink Development Company*, LLC.[101]

191. On rehearing, ISO-NE presents no evidence or argument that would undermine, in any way, the rationale underlying our ruling in the March 24 Order. Contrary to ISO-NE's assertions, for example, the Commission correctly interpreted the ISO-NE/NEPOOL arrangements regarding the socialized cost responsibility borne by all market participants with respect to third-party liabilities attributable to the acts or omissions of ISO-NE. In fact, ISO-NE concedes this point in its rehearing request.[102] By accepting the Transmission Owners' cross indemnification provisions, therefore, the Commission simply keeps in place this socialized cost responsibility by allocating to the ISO-NE RTO third-party liabilities attributable to the ISO-NE RTO's own acts or omissions. The ISO-NE RTO, in turn, is free to pass these costs through to all market participants on a socialized basis under its administrative services and capital funding tariffs.

192. We will also deny ISO-NE's requested clarifications and conditions regarding its management of these risks and the specific means by which the ISO-NE RTO will be permitted to pass any such costs through to market participants. In fact, the assurances, if any, required by the ISO-NE RTO with respect to these matters, cannot be fairly evaluated by the Commission without specific tariff language submitted for our review and consideration.

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[100] Specifically, we referenced section 10.4 of the ISO Agreement which requires NEPOOL as a whole, *i.e.*, *all* market participants, to indemnify ISO-NE for third-party liabilities attributable to ISO-NE's acts or omissions, except in cases of gross negligence or willful misconduct.

[101] 102 FERC ¶ 61,033 (2003) at P 39.

[102] *See* ISO-NE request for rehearing at 4 ("Under the current NEPOOL arrangements, each NEPOOL participant . . . retains the third-party liability to which it is subject, including third-party liabilities resulting from the acts or omission of [ISO-NE].").

## Q. Return On Equity

### 1. The March 24 Order

193. The March 24 Order found that the ROE Filers' voluntary proposal to establish the ISO-NE RTO and their commitment to transfer the day-to-day operational control authority over their transmission facilities to the ISO-NE RTO warrants a 50 basis point incentive adder, as requested, to the ROE component recovered in the ISO-NE RTO's transmission rates for Regional Network service. Accordingly, we accepted this incentive adder with respect to these facilities without suspension or hearing.

194. However, we rejected the proposed 50 basis point adder as it relates to the ISO-NE RTO's Local Service Schedules. We also accepted, subject to suspension, hearing, and subject to our Pricing Policy Statement (when issued), the ROE Filers' proposed 100 basis point adder attributable to new transmission investment. We rejected the ROE Filers' proposed 100 basis point adder as it would apply to the Local Service Schedules. Finally, we accepted, subject to suspension and hearing, the ROE Filers' proposed base level ROE. However, in order to provide the parties an opportunity to resolve these matters among themselves, we held the hearing in abeyance and instituted settlement judge procedures.

### 2. Requests for Rehearing

195. Request for rehearing of the Commission's findings in the March 24 Order regarding the ROE Filers' proposed base level ROE and ROE adders was sought by the ROE Filers and the New England Consumer Owned Entities. The following Reserved Issues are identified in the Settlement Agreement.

196. First, the ROE Filers assert that the Commission erred in rejecting their proposed 50 basis point adder for RTO participation and 100 basis point adder for new transmission investment as these adders would have related to the ISO-NE RTO's Local Service Schedules. The ROE Filers assert that while the facilities that are subject to these Local Service Schedules may be distinguishable from facilities that are part of the Regional Network Service, based on voltage and other issues, these facilities nonetheless form an integral part of the regional interstate grid, and transmission service over these facilities will be provided pursuant to the ISO-NE RTO OATT. The ROE Filers argue that the fact that a transmission asset is subject to Local Network Service Schedules does not mean that it is not integrated with the regional network or that it does not provide regional benefits. The ROE Filers argue that, as such, they should be permitted to recover both adders with respect to facilities that will be subject to Local Network Service.

197. The ROE Filers also seek clarification that the Filing Parties would be authorized to include, in their compliance filing, changes to the ISO-NE RTO OATT that would allow them to receive the 50 basis point adder for facilities classified as providing Regional Network Service. The ROE Filers explain that absent modification to the Local Service Schedules contained in schedule 21 of the ISO-NE RTO OATT, the ROE Filers would not be able to receive any benefit from the adder. The ROE Filers state that this is so because the adder would increase the Regional Network Service revenue credit without increasing the level of rolled-in cost recovery under the Local Network Services in the ISO-NE RTO OATT.

198. The ROE Filers also request clarification regarding certain policy issues relating to the calculation of their proposed base-level ROE. Specifically, the ROE Filers request clarification that they will be permitted to use a midpoint return between the high and low utilities indicated in their proposed proxy group of companies. In addition, the ROE Filers seek clarification that their proxy group, as proposed, is appropriate.

199. The New England Consumer Owned Entities assert as error the Commission's acceptance of the ROE Filers' proposed incentive adders as applicable to the Regional Network Service that will be provided by the ISO-NE RTO. The New England Consumer Owned Entities argue that these adders are unjustified to the extent they represent an above-cost ROE that will have the effect of transferring funds from non-Transmission-owning entities to the shareholders and/or retail loads of Transmission Owners or their affiliates.

### 3. <u>Commission Finding</u>

200. We will grant the clarification sought by the ROE Filers regarding the changes to Schedule 21 of the various Local Network Service Tariffs in order to properly account for the 50 basis point adder for facilities classified as providing Regional Network Service. This change recognizes that the revenues resulting from the 50 basis point adder are not to be included in the revenues credited against the total annual transmission costs for the purposes of determining the Local Network Service revenue requirements.

201. However, we will deny the ROE Filers' request for rehearing as it relates to the application of the 50 basis point adder and the 100 basis point adder to facilities subject to the ISO-NE RTO's Local Network Service Schedules. As we stated in the March 24 Order, these adders are intended to serve as an incentive for transmission owners to turn over operational control of their transmission facilities to an independent entity responsible for providing regional transmission service under the terms and conditions of a regional tariff. However, the New England wholesale electricity market, under the Filing Parties' RTO proposal, will continue to be administered under a bifurcated tariff structure under which the ISO-NE RTO will administer a regional tariff for service over Pool Transmission Facilities, i.e., high voltage facilities that serve a region-wide function.

202. By contrast, the Local Network Service Schedules, under this RTO framework, will be administered by each Transmission Owner under an individual Local OATT for service over facilities in their respective service territories, notwithstanding the coordinating role that will be played by the ISO-NE RTO regarding certain functions and services relating to these facilities. These facilities, moreover, consist of lower voltage lines or radials performing a primarily local function. The ROE Filers' request to receive incentive adders applicable to these facilities under their Local Network Service Schedules is inconsistent with our policy regarding the recovery of these adders. In fact, by definition, the Local Network facilities at issue are not used to provide Regional Network Service, nor will they be under the day-to-day operational authority of an independent entity.[103]

203. We will grant, in part, the ROE Filers' request for clarification regarding the appropriate methodology to be used to calculate their proposed base level ROE. First, we will grant the ROE Filers' request for clarification regarding the use of the midpoint return to calculate their proposed ROE.[104] We find that the use of a midpoint return is an appropriate measure for determining a single, region-wide ROE in this proceeding. This determination is consistent with our findings in the Midwest ISO proceeding where we found that the use of a midpoint return was appropriate because the companies included in the proxy group, as here, represented a diverse group of companies.[105] As such, the use of the midpoint return in this case will not result in a skewed range of distribution. Rather, it will appropriately reflect (and take due account of) the entire range of results indicated by the proxy group.

204. The ROE Filers' proposed proxy group consists of twelve utilities doing business in the Northeast, including Transmission-owning members of the ISO-NE RTO, the New York ISO, and PJM, all of whom issue share of publicly-traded stock. We believe a proxy group comprised of Northeast utility companies provides a sufficiently representative universe of companies for calculating an ROE applicable to the New England Transmission Owners in this proceeding.

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[103] Although the Local Network Service Schedules are provided pursuant to the ISO-NE RTO OATT, the day-to-day operation of these facilities will not be administered by the ISO-NE RTO; the Transmission Owens will continue to be responsible for the day-to-day operation of the facilities subject to the Local Network Service Schedules.

[104] The midpoint of all estimates of return of a proxy group is the average of the highest and lowest estimated returns of all members of the group.

[105] *See* Midwest Independent Transmission System Operator, Inc., 106 FERC ¶ 61,302 at P 8-10 (2004).

205. ROE Filers' witness, Dr. Avera, proposes that this group exclude firms that do not pay common dividends, or for which no growth rate data is currently available, as reported by I/B/E/S International, Inc. (I/B/E/S), or Value Line. We find this approach is generally acceptable. However, we will not preclude the presiding judge from finding candidates for inclusion in the proxy group for which comparable data can reasonably be substituted for the growth rate data reported by I/B/E/S or Value Line. We also find it appropriate, as Dr. Avera proposes, to exclude from consideration in the proxy group, companies whose low-end ROE was lower than these companies' reported debt cost. In addition, we agree that the inclusion of PPL Corporation (PPL) in this Proxy Group is inappropriate. Specifically, we find PPL should be excluded from the Proxy Group because its 17.7 percent cost of equity is an extreme outlier and the inclusion of this number in the calculation in an unreliable ROE that will skew the results. As Dr. Avera states in his testimony, it is often necessary to eliminate illogical results from cost of equity estimates that fail to meet threshold tests of economic logic. We believe a 13.3 percent growth rate is not a sustainable growth rate over time and therefore does not meet threshold tests of economic logic.

206. In the March 24 Order we accepted, subject to suspension, hearing and the application of our Pricing Policy Statement (when issued), the ROE Filers' proposed 100 basis point adder[106] attributable to new transmission investment. This incentive is, we stated, is an appropriate first step to encouraging vital capital investment in the enlargement, improvement, maintenance and operation of facilities for the transmission of electric energy in interstate commerce. In order to avoid any potential delay in the hearing as a result of this directive, we find it necessary to provide guidance regarding the types of investments that would qualify for this adder. We direct the parties and the presiding judge to develop a record, in this case, addressing the pros and cons of applying a 100 basis point adder for investments that, among other things: (i) are approved through the RTEP process; (ii) are capable of being installed relatively quickly; (iii) include the use of improved materials that allow significant increases in transfer capacity using existing rights-of-way and structures; (iv) utilize equipment that allows greater control of energy flows, enabling greater use of existing facilities; (v) has sophisticated monitoring and communication equipment that allows real-time rating of

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[106] This ROE adder will be applied to net book value over time of such transmission facilities (i.e., the dollar amount of the incentive that is reflected in the cost of service will decrease over time as the book value of the transmission assets are depreciated). In addition, the overall allowed equity return, adjusted for any ROE adder, will be limited to the zone of reasonableness for the public utility authorized to receive an incentive adder.

transmission facilities, facilitating greater use of existing transmission facilities; or (vi) is a new technology and/or innovation that will increase regional transfer capability.[107]

207. Finally, we will deny rehearing the New England Consumer Owned Entities' assertion that the incentive adders requested by the ROE Filers represent an unjustified above-cost return that will have the effect of transferring funds from non-transmission owning entities to the Transmission Owners' shareholders. In fact, a return on equity is not susceptible to a precise calculation. It is based, rather, on a range of reasonable returns, which take into account a number of factors that may be both cost-related and policy-related, including business risk factors. In this context, it is appropriate for the Commission to adjust the allowed return for Transmission Owners that undertake commitments designed to enhance the overall competitiveness and efficiency of the wholesale markets, so long as the resulting rate of return is within the range of reasonable returns.

The Commission orders:

(A) The Settlement Agreement is hereby accepted, subject to conditions, as discussed in the body of this order.

(B) Rehearing and/or clarification of the March 24 Order is hereby granted, in part, and denied, in part, as discussed in the body of this order.

(C) The Filing Parties' First Compliance Filing and Second Compliance Filing are hereby accepted, subject to conditions, as discussed in the body of this order.

(D) The Filing Parties are hereby directed to make a compliance filing on, or before, 30 days following the issuance of this order, as discussed in the body of this order, unless otherwise directed.

(E) The New York Filing Parties' submittal, in Docket No. ER04-943-000, is hereby accepted for filing, as discussed in the body of this order.

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[107] These technologies are fully tested and commercially available but are not widely diffused and of sufficient size and scale to have an immediate and meaningful impact on the grid.

(F) NEPOOL's submittal, in Docket No. ER05-3-000, is hereby accepted for filing, as discussed in the body of this order.

By the Commission. Commissioner Kelly not participating.
Commissioner Kelliher concurring in part with a separate statement attached.

( S E A L )

Magalie R. Salas,
Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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|---|---|
| ISO New England Inc., *et al.*, | Docket Nos. RT04-2-001, RT04-2-002, RT04-2-003, RT04-2-004, ER04-116-001, ER04-116-002, ER04-116-003, and ER04-116-004 |
| Bangor Hydro-Electric Company, *et al.*, | Docket Nos. ER04-157-002, ER04-157-003, ER04-157-005, and ER04-157-007 |
| The Consumers of New England v. New England Power Pool | Docket Nos. EL01-39-001, EL01-39-002, EL01-39-003, and EL01-39-004 |
| New York Independent System Operator, Inc., and the New York Transmission Owners | Docket No. ER04-943-000 |
| New England Power Pool | Docket No. ER05-3-000 |

(Issued November 3, 2004)

Joseph T. KELLIHER, Commissioner *concurring in part*:

I write separately to express my views on the portion of this order that directs the ISO New England, Inc.(ISO-NE) and the New England transmission owners collectively, the Filing Parties) to modify the ISO-NE Regional Transmission Organization's (ISO-NE RTO) information policy to conform with a confidential information sharing policy recently approved for PJM Interconnection, LLC.[108] In *PJM*, the Commission approved streamlined procedures for PJM to provide confidential information to state commissions, state agencies that share regulatory responsibilities with the state commissions, or any organization formed by such state regulatory commissions.

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[108] *PJM Interconnection, LLC*, 107 FERC ¶ 61,322 (2004) ("*PJM*").

As the Filing Parties point out, existing procedures are already in place that provide state entities with a process for requesting confidential information.[109] In my view, in order to justify approval of additional streamlined procedures for distributing confidential information to state entities, the Filing Parties would need to demonstrate that (1) providing state entities with confidential information possessed by the ISO-NE RTO is necessary for the state entities to discharge their legal responsibilities, and (2) the state entities cannot obtain such information under state law.[110] There is no doubt that state entities desire this information. So far, there has been no demonstration made that streamlined access to confidential information held by ISO-NE RTO is necessary to enable state entities to carry out their statutory responsibilities. There has also been no demonstration thus far that state entities are or will be unable to obtain access to confidential information from the ISO-NE RTO under state law or existing procedures. In the absence of an adequate showing on either of these critical points by the Filing Parties, I cannot support providing state commissions or other state entities with confidential information from ISO-NE RTO.

Joseph T. Kelliher

[109] *See* New England Power Pool Information Policy § 3.1(a).
[110] *PJM*, 107 FERC at 62,500 (Commissioner Kelliher, dissenting).

**Attachment to Response to PSC-2 Question No. 19(c)**
**Responding Witness – William E. Avera**

122 FERC ¶ 61,188
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Suedeen G. Kelly, Marc Spitzer,
Philip D. Moeller, and Jon Wellinghoff.

Potomac-Appalachian Transmission Highline, L.L.C. Docket No. ER08-386-000

ORDER ACCEPTING AND SUSPENDING FORMULA RATES, SUBJECT TO CONDITIONS, AND ESTABLISHING HEARING AND SETTLEMENT PROCEDURES

(Issued February 29, 2008)

1. On December 28, 2007, Potomac-Appalachian Transmission Highline, L.L.C. (PATH) filed proposed tariff sheets with the Commission, pursuant to section 205 of the Federal Power Act (FPA),[1] for inclusion within the Open Access Transmission Tariff (OATT) administered by PJM Interconnection, L.L.C. (PJM). The tariff sheets seek to implement a transmission cost of service formula rate for a proposed transmission project (Project) and implement incentive rate authorization for the Project. PATH requests that the Commission affirm its proposed incentive rate treatments consistent with Order No. 679.[2] PATH also requests that the Commission approve its formula rate without a hearing; alternatively, PATH requests that the Commission suspend the formula rate for a nominal period to permit the rate to become effective March 1, 2008 and that the Commission limit the issues set for hearing to specified elements of the formula rate or cost of service inputs where the Commission has identified issues or concerns.

2. For the reasons discussed below, we will accept the proposed formula rate subject to conditions and suspend it for a nominal period, to become effective on March 1, 2008. Moreover, we will grant PATH's requested incentive rate treatment for the Project subject to the modifications described herein. In addition, we will establish hearing and settlement judge procedures. Granting the requested incentives and accepting the proposed formula rate will aid PATH in the development of the Project.

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[1] 16 U.S.C. § 824d (2000).

[2] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222, *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

# I. Background

## A. Description of the Company

3. PATH is a joint venture between American Electric Power Company, Inc. (AEP) and Allegheny Energy, Inc. (Allegheny). PATH consists, in part, of two operating companies including PATH West Virginia Transmission Company, L.L.C., which is owned jointly by AEP and Allegheny, and PATH Allegheny Company, L.L.C., which is owned solely by Allegheny. These companies were organized to finance, construct, own, operate, and maintain the Project.

## B. The Proposed Project and Incentives

4. The Project is a proposed 290-mile transmission line that begins at AEP's Amos substation near St. Albans, West Virginia, with a terminus at the Doubs substation in Kemptown, Maryland. The Project begins as a 244 mile, 765 kV transmission line from the Amos substation to Allegheny's Bedington substation, which is northwest of Martinsburg, West Virginia. From the Bedington substation, the 765 kV line is converted into twin-circuit 500 kV lines, each 46 miles long, ending at the new Doubs substation in Kemptown, Maryland. The estimated cost of the Project is $1.8 billion and is scheduled to be completed in 2012.

5. PATH states that the Project will require numerous upgrades to the existing substations along the route.[3] For example, the Amos substation will be expanded to accommodate a new 765 kV bay by adding three new 765 kV circuit breakers and replacing two existing 765 kV circuit breakers. PATH states that two banks of 300 MVAr shunt line reactors will be installed on the 765 kV portion of the line at the Bedington substation. It further needs to install a large static VAr compensator to maximize the load-carrying ability of this line and provide the required dynamic voltage regulation. Finally, PATH will need to install a new 500 kV substation at Kemptown, Maryland.

6. PATH states that the Project is a modification of two prior, Commission-approved transmission incentive projects. The first portion of the Project (*i.e.*, the 765 kV line from the Amos substation to the Bedington substation) was considered in *AEP*,[4]

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[3] Ex. No. PTH-100 at 14-21.

[4] *American Elec. Power Serv. Corp.*, 116 FERC ¶ 61,059 (2006) (*AEP I*), *order on reh'g*, 118 FERC ¶ 61,041 (2007) (*AEP II*), (jointly, *AEP*).

and the second portion (two 500 kV lines from the Bedington substation to Kemptown, Maryland) was considered in *Allegheny*.[5]

7. PATH notes that in both *AEP* and *Allegheny* the Commission approved the following incentives: (1) an ROE at the high end of the zone of reasonableness; (2) the ability to include 100 percent of CWIP in rate base; and (3) the option to expense and recover on a current basis the costs that the companies incur during the pre-commercial or pre-operating period. Moreover, in *Allegheny* (but not in *AEP*), the Commission approved the ability to recover abandonment costs if the project was abandoned due to factors beyond Allegheny's control.[6]

8. Here, PATH seeks authorization of the following incentives: (1) approval of a 50 basis point adder to PATH's authorized ROE in recognition of its intent to become and remain a transmission owner in PJM; (2) approval of an ROE at the high end of the zone of reasonableness or, in the alternative, approval of a 150 basis point adder (in addition to the 50 basis point adder for RTO participation) to result in an overall ROE of 14.3 percent; (3) authorization to include 100 percent of CWIP in rate base; (4) permission to file for recovery of all development and construction costs if the Project is abandoned as a result of factors beyond PATH's control; and (5) permission to use a hypothetical capital structure of 50 percent debt and 50 percent equity during the construction period.[7]

9. PATH states that it is not seeking the option to expense and recover, on a current basis, on-going costs incurred during the pre-commercial period. However, PATH states that it has been, and will continue, accruing these costs in a regulatory asset account up to the date its rates become effective. PATH requests authorization to amortize the

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[5] *Allegheny Energy Inc.*, 116 FERC ¶ 61,058 (2006) (*Allegheny I*), *order on reh'g*, 118 FERC ¶ 61,042 (2007) (*Allegheny II*), (jointly, *Allegheny*).

[6] The Commission accepted a later section 205 proposal by Allegheny for rate recovery of the first portion of this project in *Trans-Allegheny Interstate Line Co.*, 119 FERC ¶ 61,219, *order on reh'g*, 121 FERC ¶ 61,009 (2007) (*TrAILCo*).

[7] PATH states that it is not proposing a hypothetical capital structure as part of its request for incentives, but rather, as a reasonable approach during the construction phase of a start-up company that will facilitate financing and is consistent with Commission precedent, *citing ITC Holdings Corp.*, 102 FERC ¶ 61,182, *reh'g denied*, 104 FERC ¶ 61,033 (2003), *order accepting letter agreement*, 107 FERC ¶ 61,077, *order on compliance addressing accounting for divestiture and ratemaking*, 107 FERC ¶ 61,089 (2004), *order authorizing disposition and confirming independence*, 111 FERC ¶ 61,149 (2005); *Michigan Elec. Transmission Co.*, 105 FERC ¶ 61,214 (2003).

regulatory asset during the construction period and include the unamortized portion of the regulatory asset costs in its rate base.[8] PATH also seeks permission to accrue Allowance for Funds Used During Construction (AFUDC) on the regulatory asset costs until the requested effective date of March 1, 2008, to reflect the time value associated with these expenditures.[9]

10. PATH argues these incentives should be granted because the Commission approved incentives in *AEP* and *Allegheny*. If, however, the Commission reviews the Project anew, PATH asserts that it satisfies the requirements of section 219 of the FPA. PATH states that it is entitled to a rebuttable presumption regarding its eligibility for transmission incentives because the Project has been approved through "a fair and open regional planning process"—*i.e.*, the PJM Regional Transmission Expansion Plan (RTEP) process. As PATH notes, the Project is a baseline upgrade in PJM's 2007 RTEP and will relieve overloading on more than 12 locations in PJM's base case study.[10] The Project will form a high-capacity transmission "backbone" overlaying and strengthening the existing system.[11]

11. PATH further explains that the Project's use of 765 kV lines and twin-circuit 500 kV lines will improve reliability. For example, the 765 kV portion represents the highest voltage class in commercial operation in North America and provides the greatest capacity and operating flexibility.[12] As compared to lower voltage lines, the 765 kV line

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[8] PATH does not present its request to expense and recover pre-commercial costs deferred as a regulatory asset as one of its requested transmission rate incentives pursuant to Order No. 679. However, this rate proposal achieves the same outcome as the Order No. 679 incentive for pre-commercial costs because such costs will be fully amortized (expensed) and recovered during the construction of the Project. As explained further in this order, this request is akin to the rate incentive for pre-commercial costs and will be reviewed under Order No. 679.

[9] PATH Filing at 15.

[10] Ex. No. PTH-106 at 1-3. Specifically, PJM has found that construction of the Project will relieve overloading at the following facilities: Keystone-Airydale 500 kV line, Keystone to Conemaugh 500 kV line, Mt. Storm to Doubs 500 kV line, Airydale to Juniata 500 kV line, Prunytown to Mt. Storm 500 kV line, Harrison to Prunytown 500 kV line, Lexington to Dooms 500 kV line, Loudoun to Pleasant View 500 kV line, Greenland Gap to Meadowbrook 500 kV line, Mt. Storm to Greenland Gap 500 kV line, Hosensack to Elroy 500 kV line, and Bath County to Valley 500 kV line.

[11] Ex. No. PTH-100 at 16, lines 10-16.

[12] *See, e.g.*, US-Canada Power System Outage Task Force, "Final Report on the
(continued...)

will be free of thermal overload risk, will experience significantly fewer forced outages, and will achieve a transmission line loss profile below 0.75 percent, whereas lower voltage lines experience transmission line losses in the three to four percent range. PATH also states that the 765 kV line will improve reliability by providing a margin for operating uncertainties, which helps to "absorb voltage and current swings and thus serve as a barrier to the spread of a cascade."[13]

12. PATH also emphasizes the reliability benefits of twin-circuit 500 kV lines between the Bedington substation and Kemptown, Maryland. PATH states that the use of twin-circuits will increase reliability in the event of a single line outage. In addition, PATH explains that twin-circuit 500 kV lines between Bedington to Kemptown will increase reliability in the event of a single line outage and will eliminate the potential for critical overloading once the project is constructed.[14]

13. Although PATH is not specifically requesting incentives for the use of innovative transmission technologies, the petition includes a technology statement as required by Order No. 679.[15] PATH states that the Project will use "advanced technology," including advanced conductor designs, phase and shield wire transposition, fiber optic shield wires, wide-area monitoring and control, remote station equipment diagnostics and security, independent phase operation to enhance line reliability, switchable shunt reactors, and a large static VAr compensation device.[16]

### C. <u>Description of Formula Rate</u>

14. PATH states that it has structured its formula rate similar to those approved in other cases.[17] PATH explains that the formula rate has (1) a statement of the annual

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August 14, 2003 Blackout in the United States and Canada: Causes and Recommendations," at 75, 77 (April 2004) (https://reports.energy.gov/BlackoutFinal-Web.pdf) (Final Report on 2003 Blackout).

[13] *Id.* at 77.

[14] Ex. No. PTH-100 at 20-21.

[15] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 302; Ex. No. PTH-100 at 30.

[16] The Commission is not viewing PATH's incentives request as an advanced technology incentive request.

[17] *American Transmission Co.*, 97 FERC ¶ 61,139 (2001); *International Transmission Co.*, 116 FERC ¶ 61,036 (2006); *Michigan Elec. Transmission Co.*,

(continued...)

transmission revenue requirement (ATRR) that will be included as Attachment H-19 of the PJM OATT; (2) the cost of service formula itself that provides detailed calculations of the annual revenue requirements (including worksheets);[18] and (3) formula rate implementation protocols in Attachment B to the ATRR.

15. PATH states that the formula rate implementation protocols describe how PATH will update the formula each year, what the review procedures will be, and how customer challenges will be resolved, and how any changes to the annual rate restatements will be implemented. For example, true-up adjustment will be determined in the following manner: the actual transmission revenues for the previous year will be compared to the net revenue requirement using its FERC Form No. 1 for that same year to determine any over or under recovery. Interest on any over or under recovery in the revenue requirement will be based on the Commission's interest rate on refunds. The Net Revenue Requirement for transmission services for the following year shall be the sum of the projected revenue requirement for the following year and a true-up adjustment for the previous year.

16. PATH states that it will recalculate its ATRR, producing the "Annual Update" for the upcoming rate year, which it will post on the PJM website on or before October 15 of each year. In addition, PATH will submit the Annual Update as an informational filing with the Commission. Each Annual Update is subject to a review procedure. Parties have 150 days after the publication date to review the calculations and notify PATH in writing of any challenges, and parties have 120 days to serve reasonable information requests on PATH. If any issues cannot be resolved, parties can make a formal challenge with the Commission.

17. PATH's formula rate implementation protocols also state that "Preliminary or Formal Challenges related to Material Accounting Changes are not intended to serve as a means of pursuing other objections to the Formula Rate. PATH notes that while it proposes that the formula rate be populated with FERC Form No. 1 numbers, it does not yet have a Form 1 on file. PATH states that therefore, it would be charging customers based on estimated costs from the requested March 1, 2008 effective date until actual Form 1 data is available in 2009, and its formula rate implementation protocols permit a true-up, in this case, on May 31, 2010. PATH states that any resulting over or under recoveries for the 2008 rate year would be reflected in customers' rates in 2011.[19] The

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113 FERC ¶ 61,343 (2005); *Xcel Energy Serv. Inc.*, 121 FERC ¶ 61,284 (2007) (*Xcel*).

[18] The formula rate and accompanying worksheets are included as Appendix A to the annual transmission revenue requirement in Attachment H-19.

[19] Ex. No. PTH-300 at 6.

formula rate implementation protocols also provide for the acceleration of crediting of any projected over recovery of the 2009 net revenue requirement, at PATH's election.

## II. Procedural History, Notice of Filings and Responsive Pleadings

18. Notice of PATH's petition was published in the *Federal Register*, 73 Fed. Reg. 2237 (2008), with interventions and comments due on or before January 18, 2008.

19. Timely motions to intervene and notices of intervention were filed by: the Maryland Public Service Commission; Exelon Corporation; the Pennsylvania Public Utility Commission; Dominion Resources Services, Inc.; the Illinois Commerce Commission; Public Service Electric and Gas Company; Blue Ridge Power Agency; PPL Electric Utilities Corporation; Pepco Holdings, Inc. and certain of its jurisdictional affiliates; North Carolina Electric Membership Corporation; West Virginia Energy Users Group; Allegheny Electric Cooperative, Inc.; and PJM. In addition, timely comments and protests were filed by: American Municipal Power-Ohio, Inc. (AMP-Ohio); Virginia State Corporation Commission (Virginia Commission); the North Carolina Agencies;[20] Southern Maryland Electric Cooperative; the Joint Consumer Advocates (JCA);[21] Delaware Municipal Electric Corporation; Old Dominion Electric Cooperative (ODEC); and Borough of Chambersburg, Pennsylvania.

20. On February 4, 2008, PATH filed a motion for leave to answer and answer to the protests in this proceeding. On February 5, 2008, PATH filed an errata to its motion for leave to answer and answer to the protests in this proceeding. On February 8, 2008, JCA filed a motion for leave to answer and answer to PATH's answer.

21. On February 8, 2008, Rockland Electric Company filed a late intervention.

[20] The North Carolina Agencies include the North Carolina Utilities Commission, Public Staff–North Carolina Utilities Commission, and the Attorney General of North Carolina.

[21] The JCA include the Pennsylvania Office of Consumer Advocate, the Maryland Office of People's Counsel, the Office of the Ohio Consumers' Counsel, the New Jersey Department of the Public Advocate, Division of Rate Counsel, the West Virginia Consumer Advocate Division, the Delaware Division of Public Advocate, and the D.C. Office of People's Counsel.

# III. Discussion

## A. Procedural Matters

22. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure,[22] the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Given the early stage of this proceeding, the absence of any undue prejudice or delay, and their interest in this proceeding, we grant the untimely, unopposed motions to intervene.

23. Rule 213(a) of the Commission's Rules of Practice and Procedure[23] prohibits an answer to a protest, unless otherwise permitted by the decisional authority. We will accept PATH's answer because it has provided information that assisted us in our decision-making process. However, the JCA's answer reiterates its earlier protest without new information. We are not persuaded to allow the JCA's answer, and accordingly we will reject it.

## B. Discussion of Incentive Rates

24. In Energy Policy Act of 2005 (EPAct 2005),[24] Congress added new section 219 to the FPA directing the Commission to establish, by rule, incentive-based rate treatments to promote capital investment in transmission infrastructure. The Commission subsequently issued Order No. 679, which sets forth processes by which a public utility could seek transmission rate incentives pursuant to section 219, including the incentives requested here by PATH.

25. Pursuant to section 219, an applicant must show that "the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion." Also, as part of this demonstration, ". . . section 219(d) provides that all rates approved under the Rule are subject to the requirements of sections 205 and 206 of the FPA, which require that all rates, charges, terms and conditions be just and reasonable and not unduly discriminatory or preferential."[25]

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[22] 18 C.F.R. § 385.214 (2007).

[23] *Id.* § 385.213(a)(2).

[24] Pub. L. No. 109-58, 119 Stat. 594, section 1241.

[25] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 8 (*citing* 16 U.S.C. §§ 824(d) and 824(e)).

26. Finally, in addition to satisfying these section 219 requirements, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. As explained below, we find that PATH has satisfied the requirements for incentive rate treatment for the Project and will grant PATH's requested incentives subject to the conditions noted below.

### 1. ROE Adder for RTO Participation

#### a. Protests

27. No party protested PATH's requested 50 basis point ROE adder for RTO participation.

#### b. Commission Determination

28. We will grant PATH's request to increase its ROE by 50-basis points conditioned upon PATH's membership application being approved by PJM and its continued participation in PJM, and conditioned upon the final ROE being within the zone of reasonable returns. As we emphasized in Order No. 679-A, the Commission will approve, when justified, incentives to each transmitting utility that joins a Transmission Organization.[26] The consumer benefits for participating in such an organization, including reliable grid operation, are well documented and consistent with section 219. PATH's request for an incentive based on RTO participation is consistent with the Commission's well established policy and will be granted subject to the conditions in this order.

### 2. Section 219 Requirements

29. Order No. 679 provides that a public utility may file a petition for declaratory order or a section 205 filing to obtain incentive rate treatment for transmission infrastructure investment that satisfies the requirements of section 219, *i.e.*, the applicant must demonstrate that the facilities for which it seeks incentives either ensure reliability or reduce the cost of delivered power by reducing transmission congestion.[27] An applicant will be entitled to a rebuttable presumption under section 219 if: (i) the transmission project results from a fair and open regional planning process that considers

[26] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 86. Under Order No. 679, a Regional Transmission Organization such as PJM qualifies as a Commission-approved Transmission Organization for purposes of eligibility for the Transmission Organization incentive. Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 328.

[27] 18 C.F.R. § 35.35(i).

and evaluates projects for reliability and/or congestion and is found to be acceptable to the Commission; or (ii) a project has received construction approval from an appropriate state commission or state siting authority."[28] Order No. 679-A also clarifies the operation of this rebuttable presumption by noting that the authorities and/or processes on which it is based (*i.e.*, a regional planning process, a state commission, or siting authority) must, in fact, consider whether the project ensures reliability or reduces the cost of delivered power by reducing congestion.[29]

### a. Protests

30. No party questions PATH's entitlement to a rebuttable presumption under section 219.

### b. Commission Determination

31. We find the Project satisfies the requirements for a rebuttable presumption for eligibility for transmission incentives under section 219. As PATH noted in its filing, the Project has been vetted and approved as part of PJM's 2007 RTEP, which constitutes "a fair and open regional planning process."[30] Moreover, there is substantial evidence that the Project ensures reliability by substantially reducing overloads on the current system and reduces the cost of delivered power by reducing congestion on 12 major 500 kV transmission routes in the region.[31] Accordingly, we find that PATH has satisfied the first prong of the Commission's incentives test under section 219.

## 3. The Nexus Requirement on all Incentives, and Section 205 Requirements on CWIP and ROE

32. In addition to satisfying the section 219 requirement, an applicant must demonstrate that there is a nexus between the incentive sought and the investment being made. The Commission has stated that in evaluating whether an applicant has satisfied the required nexus test, the Commission will examine the total package of incentives being sought, the interrelationship between any incentives, and how any requested incentives address the risks and challenges faced by the applicant in constructing the

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[28] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 58.

[29] *Id.* P 49.

[30] *Duquesne Light Co.*, 118 FERC ¶ 61,087, at P 62-68 (2007), *reh'g pending* (*Duquesne*).

[31] Ex. No. PTH-106 at 2.

project.[32] By its terms, this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.[33] Applicants must provide sufficient explanation and support to allow the Commission to evaluate the incentives.

33. The Commission also finds that the Project satisfies the nexus requirement for each of the incentives as set forth below. PATH is undertaking considerable risk and challenges to develop and construct the Project. It has demonstrated a nexus between those risks and challenges and the incentives that it has requested. Accordingly, we will grant those incentives subject to the conditions set forth below.

**a. 100 Percent of CWIP**

34. In Order No. 679, the Commission established a policy that allows utilities to include, where appropriate, 100 percent of prudently-incurred transmission-related CWIP in rate base.[34] We noted that this rate treatment will further the goals of section 219 by providing up-front regulatory certainty, rate stability, and improved cash flow for applicants thereby reducing the pressures on their finances caused by investing in transmission projects.[35]

35. PATH seeks authorization to place in rate base 100 percent of prudently-incurred transmission-related CWIP prior to the in-service date of the Project. PATH identifies the primary benefit of this incentive treatment as the reduced costs to transmission customers as a result of the lower cost of debt that the utility can obtain when it includes CWIP in rate base.[36]

36. PATH explains that the Project is a major undertaking in terms of scope and cost, involving construction across two states, multiple siting and permitting approvals, and a significant amount of business risk. The Project also has an estimated cost of $1.8

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[32] 18 C.F.R. § 35.35(d); Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26. *See also* Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21 ("[T]he incentive(s) sought must be tailored to address the demonstrable risks and challenges faced by the applicant in undertaking the project.").

[33] *See* Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 18.

[34] *Id.* P 29, 117.

[35] *Id.* P 115.

[36] Dr. Joensen's Testimony, Exhibit No. PTH-200 at 18.

billion.[37] PATH further notes the increased financial risk of the Project due to its long construction time, as the projected completion date is in 2012. For all these reasons PATH states: "It is essential, therefore . . . for the PATH project . . . to induce the capital markets to participate in the PATH project, and to do so on terms that will be most beneficial to those assigned cost responsibility for the project."[38]

37. PATH points out that a start-up company, from the perspective of investors and lenders, does not have an established credit rating or a debt repayment or earnings history.[39] Financing for start-ups, then, is available based largely on projections of cash flow.[40] Moreover, PATH argues that including 100 percent of CWIP in rate base provides benefits to ratepayers and does not change the net present value to shareholders of the cash flow.[41]

#### i. <u>Protests</u>

38. While protesters do not contest the inclusion of CWIP in the formula as an individual incentive, they do take issue with the amount of CWIP to be included in the formula. These issues will be addressed in the Formula Rates and Estimated Inputs section of this order.

#### ii. <u>Commission Determination</u>

39. PATH explains that the Project is a major undertaking in terms of scope and cost, involving construction across two states, multiple siting and permitting approvals, and a significant amount of business risk. The Project has an estimated cost of $1.8 billion and has a long construction time of approximately five years.[42] PATH also faces risks as a start-up company. PATH notes that start-up companies do not have established credit ratings, debt repayment history, or earnings history; thus, financing for start-ups is largely influenced by a company's cash flow.[43]

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[37] PATH Filing at 12.

[38] Ex. No. PTH-200 at 28.

[39] *Id.* at 23.

[40] *Id.* at 25.

[41] *Id.* at 24.

[42] PATH Filing at 12.

[43] Ex. No. PTH-200 at 23, 25.

40. Consistent with Order No. 679, we find that authorizing 100 percent of CWIP would enhance PATH's cash flow, reduce interest expense, assist with financing, and improve coverage ratios used by rating agencies to determine credit quality by replacing non-cash AFUDC with cash earnings. Considering the size, scope, and construction lead time of the Project, we find that authorization of the CWIP incentive is appropriate to assist in the construction of this new transmission facility.

41. This notion is especially true given PATH's status as a start-up company. Cash flow projections provided in Exhibit PTH-201 indicate that PATH expects revenues from CWIP recovery to total over $430 million during the construction period from 2008 to 2012. The Commission believes this substantial increase in cash flow will greatly assist PATH's ability to obtain financing for the Project.

42. We also find that CWIP will result in better rate stability for customers. As we have explained before, when certain large scale transmission projects come on line there is a risk that consumers may experience "rate shock" if CWIP is not permitted in rate base.[44] By allowing CWIP for the Project, the rate impact of the Project can be spread over the entire construction period and will help consumers avoid a return on and of capitalized AFUDC.[45]

43. Finally, consistent with the section 205 requirements for CWIP as required by 18 C.F.R. § 35.25, PATH has an obligation to propose accounting procedures that ensure that customers will not be charged for both capitalized AFUDC and corresponding amounts of CWIP in rate base. PATH proposes to fulfill these requirements in Exhibit No. PTH-500. PATH proposes to use a software program to maintain its accounting records for electric plant assets during construction and when the project is placed in service. Further, it states that this system can calculate and capitalize AFUDC based on specific work orders, and all work orders for construction of the Project will be identified to ensure that no AFUDC is calculated on their balances.[46] The Commission finds that these procedures are sufficient.

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[44] *See, e.g.*, *AEP*, 116 FERC ¶ 61,059 at P 59, *order on reh'g*, 118 FERC ¶ 61,041 at P 27.

[45] *Id.*

[46] *See* PATH Filing, Appendix H at 4-5. *See also* Ex. No. PTH-500.

### b. Abandonment Costs

#### i. Protests

44. While several protesters argue the combination of incentives inclusive of the abandonment incentive, no party protests the abandonment incentive individually.

#### ii. Commission Determination

45. In Order No. 679, we found that this incentive is an effective means to encourage transmission development by reducing the risk of non-recovery of costs.[47] We will grant PATH's request for recovery of 100 percent of prudently-incurred costs associated with abandonment of the Project, provided that the abandonment is a result of factors beyond the control of PATH, which must be demonstrated in a subsequent section 205 filing for recovery of abandoned plant.[48]

46. We find that PATH has shown, consistent with Order No. 679, a nexus between the recovery of prudently-incurred costs associated with abandoned transmission projects and its planned investment. These risks are especially significant for large scale projects, like the Project, that require multistate and federal approvals prior to completion. Granting PATH's request for an abandonment incentive will help to ameliorate these risks and help ensure the completion of the Project.

47. The Commission will not determine the justness and reasonableness of PATH's abandoned plant recovery, if any, until PATH seeks such recovery in a section 205 filing. Order No. 679 specifically reserves the prudence determination for the later section 205 filing which every utility is required to make if it seeks abandonment recovery.[49] At this stage of the proceeding, we are granting this incentive, subject to PATH making the appropriate demonstration in a future section 205 filing.

### c. Pre-Commercial Costs

#### i. Protests

48. AMP-Ohio argues that PATH does not justify its proposal to amortize development [pre-commercial] costs over 60 months. AMP-Ohio states that PATH fails

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[47] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 163.

[48] *Id.* P 165-66.

[49] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 165-66.

to explain why these costs should not be amortized over the depreciable life of the asset, consistent with traditional treatment of these types of costs.

### ii. Commission Determination

49. Like CWIP, in Order No. 679, the Commission permitted public utilities to expense prudently incurred pre-commercial costs to provide up-front regulatory certainty, rate stability, and improved cash flow for applicants.[50] Although PATH states that it is not requesting this incentive rate treatment for pre-commercial costs, PATH is attempting to recover such costs by deferring them as a regulatory asset and amortizing it during the construction period of the Project.

50. PATH's proposed recovery of pre-commercial costs, like the rate incentive for pre-commercial costs in Order No. 679, is different from the Commission's traditional accounting and ratemaking treatment for pre-commercial costs. Traditionally, pre-commercial costs are deferred until construction of the project begins.[51] Once construction of the project commences, the pre-commercial costs are transferred to Account 107,[52] accrue AFUDC, and provide no cash flow during the construction period. Here, PATH proposes a mechanism where the pre-commercial costs are expensed through amortization and recovered in its formula rate during the construction period, providing the same effect as the rate incentive for pre-commercial costs in Order No. 679. Accordingly, we will review PATH's request to recover these costs as a request for incentives under Order No. 679.[53]

51. In Order No. 679, the Commission stated the types of pre-commercial operations costs to be expensed, rather than capitalized, are the preliminary survey and investigation (PSI) costs in Account 183. The Commission also noted that it will entertain proposals to expense other types of costs for consideration on a case-by-case basis.

52. PATH generally proposes to amortize (expense) deferred PSI costs and PATH start-up and business administration costs during the construction period. Contrary to AMP-Ohio's assertion, we find that authorizing the expense and recovery of these

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[50] *Id.* P 115.

[51] For example, expenditures for preliminary surveys, plans, and investigations made for the purpose of determining the feasibility of utility projects under contemplation are deferred in Account 183 until construction of the project begins.

[52] Account 107, Construction Work in Progress – Electric.

[53] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 115, 122.

deferred pre-commercial costs would enhance PATH's cash flow during the construction period, reduce interest expense, assist with financing, and improve coverage ratios used by rating agencies to determine credit quality. Further, considering the size, scope, and construction lead time of the Project, we find that this incentive will assist in the construction of this new transmission facility. Accordingly, we conditionally grant PATH an incentive to recover its pre-commercial costs related to the construction of the Project.

### d. Hypothetical Capital Structure

#### i. Protests

53. While several protesters argue the combination of the hypothetical capital structure and PATH's requested ROE incentive, no party protested the hypothetical capital structure as a stand-alone incentive.

#### ii. Commission Determination

54. As stated in Order No. 679, use of hypothetical capital structures "can be an appropriate ratemaking tool for fostering new transmission in certain relatively narrow circumstances."[54] The Commission found, however, that adoption of such a hypothetical capital structure would require a demonstration of the required nexus between the need for a hypothetical capital structure and the proposed investment project.[55] While PATH does not request the use of the hypothetical capital structure as a formal incentive, the Commission has an obligation to determine whether the nexus has been satisfied under Order No. 679. We believe that PATH has met that burden in this case.

55. PATH has sufficiently demonstrated that permitting this treatment will result in lower debt costs for the company, while also permitting it to vary its financing vehicles to the needs of the construction process, including such issues as timing of expenditures, regulatory developments, and changes in financial market conditions. Moreover, we find that the use of a hypothetical capital structure of 50 percent debt and 50 percent equity during the Project's construction period is a pragmatic approach to address PATH's fluctuating capital structure.[56]

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[54] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 93.

[55] *Id.*

[56] *See TrAILCo*, 119 FERC ¶ 61,219 at P 74-76.

56. Upon completion of the Project, the Commission directs PATH to adopt a capital structure based upon its actual financing presented in its Form No. 1, consistent with Commission precedent for PJM Transmission Owners with formula rates.[57] PATH does not provide a sufficient nexus for the use of a hypothetical capital structure once the Project financing is completed or the need for flexibility when construction is completed.

### e. ROE Incentives

57. As noted earlier, in Order No. 679-A, the Commission clarified that its nexus test is met when an applicant demonstrates that the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant."[58] The Commission noted that this nexus test is fact-specific and requires the Commission to review each application on a case-by-case basis.

58. The Commission recently provided clarification on the nexus test. Specifically, it noted that in evaluating whether the total package of incentives requested is "tailored to address the demonstrable risks or challenges faced by the applicant," the question of whether a project is routine is probative.[59] The Commission elaborated on how it will evaluate projects to determine whether they are routine and the effect this evaluation has on an applicant's request for incentives.[60] The Commission stated that: (1) it will

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[57] All of the PJM transmission owners with this type of formula rate calculate their capital structures based upon actual data in their FERC Form No. 1. *See* Atlantic City Electric Company, Baltimore Gas & Electric Company, Delmarva Power & Light Company, Potomac Electric Power Company, Commonwealth Edison Company, and UGI Utilities, as filed in their formula rates under the PJM OATT, FERC Electric Tariff, Sixth Rev. Vol. No. 1, Att. H-1, H-2, H-3, H-9, H-13 and H-8C, respectively.

[58] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

[59] *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084, at P 48 (2007) (*BG&E*).

[60] In that respect, the Commission explained its determinations regarding routine investments in Order Nos. 679 and 679-A:

> [W]e held in Order No. 679 that routine investments "may not always qualify" for incentives. However, we did not find that they would never qualify. Similarly, in Order No. 679-A, we held that projects with "special risks and challenges" present "the most compelling case" for incentives, but did not hold they are the only projects that can qualify for incentives. Second, we held that routine investments "to meet existing reliability standards" may not always qualify for incentives. However, we did not hold that, if a project's primary or sole purpose is to maintain reliability, it

(continued...)

consider all relevant factors presented by the applicant to determine whether or not a project is routine;[61] and (2) applicants must provide detailed factual information in support of the factors they rely upon.[62] Additionally, the Commission clarified that "when an applicant has adequately demonstrated that the project for which it requests an incentive is not routine, that applicant has, for purposes of the nexus test, shown that the project faces risks and challenges that merit an incentive."[63] Finally, the Commission stated that if it determines that a project is routine, an applicant is not foreclosed from the requested incentive; it may show that its project faces risks and challenges or provides sufficient benefits to warrant incentive rate treatment.[64]

### i. PATH's ROE Request

59. In its filing, PATH seeks an ROE at the high end of the zone of reasonableness or, in the alternative, approval of a 150 basis point adder (in addition to the 50 basis point adder for RTO participation) to result in an overall ROE of 14.3 percent.

60. With respect to the nexus requirement, PATH states that an incentive ROE is necessary to address the following risks: (1) the large size of the financial investment;

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> should not be eligible for incentives. Indeed, to do so would have been to disregard the plain language of section 219, which required the Commission to adopt a rule that "promote[s] reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce."

*Id.* P 51 (footnotes omitted).

[61] These factors include, but are not limited to: (1) the scope of the project (*e.g.*, dollar investment, increase in transfer capability, involvement of multiple entities or jurisdictions, size, effect on region); (2) the effect of the project (*e.g.*, improving reliability or reducing congestion costs); and (3) the challenges or risks faced by the project (*e.g.*, siting, internal competition for financing with other projects, long lead times, regulatory and political risks, specific financing challenges, other impediments). *Id.* P 52.

[62] *See id.* P 53.

[63] *Id.* P 54.

[64] *Id.* P 55.

(2) the need for coordination between Allegheny and AEP over two service territories; (3) regulatory risks; (4) the need to attract investment; (5) the need for siting approval in two states; and (6) the fact that PJM has established an aggressive timetable for the Project to be placed into service. PATH explains the risks involved with siting given the size of this Project, by referencing AEP's Jacksons Ferry-Wyoming 765 kV transmission line, located in Virginia and West Virginia spanning 90 miles. PATH states that for AEP's Jacksons Ferry-Wyoming 765 kV transmission line, the siting alone took 13 years and cost $50 million out of the total $306 million cost, involving two state commissions and five federal agencies.[65]

61. PATH provides a discounted cash flow analysis (DCF) using a single step constant growth rate calculation, and a proxy group of northeast utilities, to result in a range of reasonable returns of 7.9 percent to 16.7 percent, with a midpoint of 12.3 percent. PATH states that based on its DCF, its requested ROE is within the range of reasonable returns and therefore, just and reasonable.[66]

62. PATH proposes a proxy group of 15 transmission owners with publicly-traded stock in the Northeast,[67] consistent with the approach approved in *Opinion No. 489*.[68] PATH states that this 15 company proxy group was a result of eliminating utilities that: (1) do not pay common dividends; (2) for which no International Brokers Estimation

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[65] Ex. No. PTH-100 at 34.

[66] Ex. No. PTH-400.

[67] These 15 companies are: American Electric Power Co., Central Vermont Public Service, Consolidated Edison, Inc., Constellation Energy Group, Dominion Resources, DPL Inc., Exelon Corporation, FirstEnergy Corporation, FPL Group, Inc., Northeast Utilities, NSTAR, Pepco Holdings, Inc., PPL Corporation, Public Service Enterprise Group, and UIL Holdings.

[68] The Commission authorized the establishment of ISO New England as an RTO, and permitted certain ROE incentives in a series of orders issued effective as of the date of RTO operations. *See ISO New England, Inc.*, 106 FERC ¶ 61,280, at P 249 (*RTO Order*), *order on reh'g and compliance*, 109 FERC ¶ 61,147 (2004) (*RTO Rehearing Order*) (granting the RTO operations effective date of February 1, 2005), *order on reh'g and compliance*, 110 FERC ¶ 61,111 (*February 10, 2005 Order*), *order on reh'g and compliance*, 110 FERC ¶ 61,335 (2005) (*March 24, 2005 Order*), *order on reh'g*, 111 FERC ¶ 61,344 (2005) (*June 2, 2005 Order*), *Bangor Hydro-Electric Co.*, 111 FERC ¶ 63,048 (2005) (*Initial Decision*), *Bangor Hydro-Electric Co.*, *Opinion No. 489*, 117 FERC ¶ 61,129 (2006) (*Opinion No. 489*), *reh'g pending*.

System International, Inc. (IBES) or Value Line data was available; (3) were in the process of merger proceedings;[69] and (4) have primary business operations as natural gas pipelines.[70]

63. Further, PATH explains that to be consistent with the Supreme Court's findings in *Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*[71] and *FPC v. Hope Natural Gas Co.*,[72] its DCF analysis incorporated the measures of investment risk.[73] PATH states that "expanding the proxy group to include utilities operating in adjacent Transmission Organizations and facing similar circumstances helps to avoid regional discriminations with no underlying economic justification, and provides greater assurance that the resulting ROEs will further the policy goals of this Commission and the Congress."[74]

64. PATH explains that corporate credit ratings are widely cited in the investment community and referenced by investors as an objective measure of risk, noting that the Commission relied on corporate credit ratings as the "single defining risk indicator" in its decision to establish an allowed ROE above the midpoint of the zone of reasonableness in *Opinion No. 445*.[75]

65. PATH states that the salient criteria in establishing a meaningful proxy group to estimate investor's required return is comparable risk within the proxy group, under the regulatory standards of *Hope* and *Bluefield*. Relying on the published corporate credit

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[69] In Ex. No. PTH-400 at 30, PATH states that it eliminated Energy East Corporation from the proxy group because it has agreed to be acquired.

[70] *Id.* at 30. PATH states that it excluded UGI Corporation consistent with the Commission's findings in *Opinion No. 489*, 117 FERC ¶ 61,129 at P 37, given its primary status as a natural gas company.

[71] 262 U.S. 679 (1923) (*Bluefield*).

[72] 320 U.S. 591 (1944) (*Hope*).

[73] Ex. No. PTH-400 at 6, 36. Specifically, PATH has chosen Standard and Poor's (S&P) corporate credit ratings, Value Line's Safety Rankings, and Financial Strength Rating as the objective measures of risk in developing its proxy group.

[74] *Id.* at 34.

[75] *Southern California Edison Co.*, 92 FERC ¶ 61,070, at 61,264 (2000) (*Opinion No. 445*).

ratings of its parent companies; AEP (BBB) and Allegheny (BBB-), and relying on additional investment risk criteria,[76] PATH states that its proxy group is consistent with this standard.[77]

### ii. Protests

66. JCA argues that circumstances have materially changed since the granting of incentives *AEP* and *Allegheny* and that the risks to PATH have, as a result, been reduced. Specifically, the sum of the proposed costs of the two earlier projects is more than twice the cost of the current Project and would have taken twice as long to complete, according to JCA. Therefore, JCA requests that there should either be no additional ROE incentive allowed beyond the 50 basis point RTO membership incentive, or the requested 150 basis points should be greatly reduced and the exact number should be determined at an evidentiary hearing.

67. AMP-Ohio questions the need for such a high ROE since AEP has "double-leveraged" PATH and will be receiving a higher return based on this business structure.[78]

68. Protesters state that PATH's general discussions of risk do not support a finding that any particular ROE is required, let alone an ROE of 14.3 percent. Protesters state that for example, while PATH cites to the "sheer size" of the Project, it does not discuss the size of the Project in relative terms compared to the existing transmission rate base of AEP or Allegheny.[79]

69. Protesters state that the risk factors identified by PATH counterbalance considerations showing that a lower ROE would be sufficient. First, protesters state that the fact that two large experienced companies are partnering on the Project ameliorates the risks of the Project and facilitates the best practices of each company. Second, protesters state that the fact that the Project is intended to go into service relatively quickly tends to offset risks. Third, protesters state that both AEP and Allegheny have extensive experience with the relevant authorities in each state where the project is to be constructed, further mitigating risk. Fourth, protesters state that PATH's assertion that it is exposed to more risk as a start-up company is belied by the fact that both AEP and

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[76] Such as Value Line's Safety Rankings and Financial Strength Rating.

[77] Ex. No. PTH-400 at 37.

[78] AMP-Ohio Protest at 8.

[79] ODEC Protest at 10 (*citing Southern California Edison Co.*, 121 FERC ¶ 61,168, at P 45 (2007)).

Allegheny will derive benefits from the corporate structure of the Project. For example, while AEP and Allegheny create new entities to file formula rates with multiple incentives for new transmission investment, the revenue requirements for their existing transmission facilities (which are depreciating each year) are fixed under "stated rates" in PJM and remain insulated from review except through a complaint under section 206 of the FPA.

70. Protesters state that the Project will be initially financed through equity infusions from AEP and Allegheny.[80] Protesters point out that as a result of this "start-up", both AEP and Allegheny will have an incentive to fund this "equity" infusion with debt at a lower cost, while still recovering the higher cost "equity" return on this debt capital from ratepayers. ODEC states that this problem is compounded by an ROE incentive. In this scenario, when profits from transmission subsidiaries like PATH are transferred to the parent company there is a potential that the subsidiary's equity component (resulting from the incentive adders) will end up in the parent company equity on which further incentive adders may be sought.

71. In addition, JCA argues that it is inappropriate for the Commission "to provide incentives when AEP and Allegheny create new entities to file formulary rates with multiple incentives for new major transmission investment while the revenue requirements for the remainder of their transmission facilities (that are depreciating each year) are fixed under zonal rates in PJM."[81]

72. Protesters state that PATH uses companies in its proxy group where only 16 percent or less of their revenues are derived from regulated electric utility operations.[82]

73. Protesters point out that while PATH's approach of including companies that own transmission assets in any of the northeast RTOs may be acceptable for determining an allowable ROE for multiple companies, such as the ISO New England case, that is not the objective here. Protesters state that here, the objective is to develop an ROE for a single company alone, and therefore the proxy group should be comprised of companies

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[80] ODEC Protest (*citing* Ex. No. PTH-200 at 13-14).

[81] JCA Protest at P 43.

[82] Specifically, ODEC and JCA point to Constellation Energy Group and Exelon Corporation. ODEC Protest at 27; JCA Protest at P 48.

who truly are comparable in risk to, and representative of PATH. JCA disagrees with Dr. Avera's rejection of any linkage between a proxy company's source of revenues, the risks related to those sources, and the ultimate returns required by investors.[83]

74. Protesters argue that PATH's proxy group deviates from the northeast proxy group permitted in *Opinion No. 489*. Protesters state that PATH's use of three companies in the proxy group, Constellation Energy Group, PPL Corporation, and Exelon Corporation, are not comparable in risk to PATH, because their high-end growth rates are not sustainable. Thus, their inclusion in the proxy group fails the test of economic logic. For example, protesters point out that the growth rate for Constellation Energy Group is 16 percent in PATH's proxy group calculation. Protesters state that this is higher than the 13.3 percent growth rate that the Commission found unsustainable in the *RTO Rehearing Order* for the New England transmission owner proxy group.[84]

75. Protesters state that PATH presents its parent company's (AEP) zone of reasonable returns as 9.3 percent to 9.7 percent, with a midpoint of 9.5 percent. Protesters state that PATH does not justify or explain how the use of AEP as its parent company would not be an appropriate proxy. Protesters state that significant weight should be given to the use of the parent company in the DCF analysis.

76. Protesters state that the Commission should rely on the median of PATH's zone of reasonable returns of 9.7 percent, rather than the midpoint of 12.3 percent as the base ROE. Protesters state that in *Northwest Pipeline Corp.*,[85] the Commission determined that the median best represented the central tendency in a skewed distribution and is therefore preferable to the midpoint. The Commission stated that since the midpoint is the average of the highest and lowest numbers in the group, it is clearly subject to

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[83] JCA disagrees, for example, with the inclusion of Exelon Corporation in the proxy group, since approximately 50 percent of its revenues are derived from power generation. *See* JCA Protest at P 50.

[84] In the *RTO Rehearing Order*, 109 FERC ¶ 61,107 at P 204, the Commission excluded PPL from the New England transmission owner proxy group prior to setting the ROE for hearing because PPL's growth rates were unsustainable. As part of the subsequent hearing proceedings, the Presiding Judge found that PPL's growth rates had decreased to sustainable levels after the *RTO Rehearing Order* was issued, and therefore PPL was no longer an "outlier." *See Initial Decision*, 111 FERC ¶ 61,048 at P 62. In *Opinion No. 489*, 117 FERC ¶ 61,129 at P 24-28, the Commission affirmed the Presiding Judge's finding that PPL's growth rates had decreased to sustainable levels, and subsequently included PPL in the New England transmission owner proxy group.

[85] 99 FERC ¶ 61,305, at 62,276 (2002).

distortion by extremely high or low values. The Commission supported its rationale for using the median through statistical texts and concepts that are applicable generically to any numerical distribution, not merely a pipeline DCF-calculated ROE distribution.[86]

77. Applying this Commission policy, ODEC provides a DCF analysis of 7.9 percent to 14.3 percent, with a midpoint of 11.1 percent, and a median of 9.7 percent. In its DCF analysis for PATH, ODEC eliminates both the low-end and high-end returns for several companies. ODEC eliminates Dominion Resources, UIL Holdings and Central Vermont Public Service as outliers because their low-end DCF is too close to the cost of debt. ODEC eliminates Constellation Energy Group and Exelon Corporation because their high-end growth rates are not sustainable. ODEC further states that while PATH's DCF lists an IBES growth rate of 12 percent for PPL Corporation, 14 percent is the current IBES growth rate for PPL Corporation according to the latest S&P earnings guide. ODEC states that the 12 percent is very near, and the 14 percent is above, the 13.3 percent to be found unsustainable by the Commission in the *RTO Rehearing Order*. Because of this, ODEC eliminates PPL Corp. from its DCF calculation for PATH.

78. Protesters further question PATH's inclusion of certain companies based on their regional location. For example, AMP-Ohio points out that PATH only used companies from New York and New England, but failed to include companies from the Midwest ISO. Moreover, JCA takes issue with PATH's inclusion in the proxy group of companies without a direct link to PJM. JCA cites to *TrAILCo* to highlight the Commission's finding that the burden should be placed on the applicant to demonstrate why companies lacking a direct link to the relevant RTO should be included in the proxy group from which the zone of reasonableness for its ROE will be derived.

79. Protesters request that either the Commission issue a deficiency letter, reject the filing, or in the alternative, suspend the ROE and set it for a full evidentiary hearing.

### iii. PATH's Answer

80. In arguing that it has met the nexus requirement, PATH states that the cash flow analysis in Dr. Joenson's testimony is based on the projected earnings of PATH during the construction period and the year when the plant is to go into service and demonstrates the need for increased cash flow. Further, PATH argues that while protesters criticize Dr. Joenson's cash flow analysis for not preparing sensitivity analyses to determine whether ROE levels other than the one requested would produce satisfactory coverage ratios, the protests ignore the other two independent bases of support for the requested 14.3 percent ROE. Specifically, PATH asserts the other two forms of support were:

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[86] ODEC explains in more detail the skewed effect of PATH's proxy group distribution by its use of the midpoint. ODEC Protest at 32.

(1) the analyses presented by Dr. Joenson and Dr. Avera of the Project's risk and the nexus to the requested 150 basis point incentive adder, in light of the Commission precedent discussed in this testimony as will as in the filing's transmittal letter; and (2) the DCF analysis presented by Dr. Avera. PATH states that the absence of a sensitivity analysis does not detract from the basic conclusion that PATH has supported its request for a 14.3 percent incentive-based ROE, or, alternatively, a 150 basis point adder to the base ROE determined at hearing.

81. PATH states that protesters incorrectly assert that Dr. Joenson should have used the S&P's risk profiles of American Transmission Company and ITC Holdings Corporation in development of his coverage ratio, stating that these companies are not comparable to PATH because they hold operating assets that generate substantial cash flow, whereas PATH is a start-up company with no operating assets. PATH states that it has a greater degree of risk and is appropriately classified with companies with higher business risk profiles. Further, PATH states that ODEC's calculation of cash flows, in developing a coverage ratio analysis[87] are inconsistent with how the financial community calculates coverage ratio analyses and provide no meaningful information.

82. PATH avers that while it does not seek authorization of an incentive-based ROE adder specific to advanced technologies involved in the PATH project, it urges the Commission to consider the unchallenged support provided in the rate filings as part of its evaluation of the requested 150 basis point adder and/or PATH's requested incentive ROE of 14.3 percent.

83. PATH states that it provided three independent bases to support the requested ROE incentive: the analysis of risks in light of Commission precedent on the ROE incentive, the DCF analysis demonstrating the resulting ROE within the range of reasonable returns, and the cash flow analysis demonstrating the need for increased cash flow. PATH states that its demonstrations amply support the need for, and the justness and reasonableness of, the requested ROE incentives. PATH argues that the Commission has already found that all baseline projects within the PJM RTEP are, by definition, non-routine, and therefore worthy of incentives.[88] PATH states that consistent with prior orders granting incentives, the Commission should grant the incentives here.

84. PATH states that it developed its proxy group consistent with the Commission's direction in *Opinion No. 489* and *Duquesne* using utilities "with a direct correlation to

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[87] Specifically, Earnings Before Interest and Taxes/Interest ratios.

[88] PATH Answer at 6 (*citing BG&E*, 120 FERC ¶ 61,084 at P 54, 58; *Commonwealth Edison Co.*, 119 FERC ¶ 61,238, *order on reh'g* 122 FERC ¶ 61,037, at P 27 (2008)).

PJM or to the broader markets with which PJM interacts."[89] PATH states that after applying the Commission's one-step DCF model to the Northeast transmission owner proxy group, the resulting cost of equity estimates ranged from a low of 1.4 percent to a high of 21.1 percent. PATH states that it then applied the same tests of economic logic adopted by the Commission in several prior cases, eliminating low-end estimates (*i.e.*, those that are essentially equal to or below the yield offered by senior long-term debt) and extreme high-end outliers that fail the fundamental tests of economic logic.[90]

85. PATH states that protesters err in stating that Commission policy requires PATH to remove utilities from its proxy group that rely upon non-transmission sources of revenues. PATH states that the Commission has rejected this argument on multiple occasions, specifically, in *Midwest ISO I*, the Commission concluded that "[w]e are unpersuaded ... that transmission investments are less risky than the other investments of the Midwest ISO TO proxy companies."[91] PATH states that similarly, in *Opinion No. 489*, the Commission upheld this position, rejecting arguments that PPL Corporation and Exelon Corporation should be removed from the northeast utility company proxy group, because these utilities "provide a sufficiently representative universe of companies for calculating an ROE in this case . . ."[92] despite their non-transmission, non-regulated branches of operations.

86. PATH states that protesters err in their assertion that its DCF is flawed because it did not eliminate both the low-end *and* the high-end results for a company when one of these results defied economic logic. PATH states that the protesters mischaracterize the *Opinion No. 489* proceedings. PATH states that the Commission did not require that low-end *and* high-end results for a company should be eliminated when one of these results defied economic logic, but rather, the Commission was responding to protests requesting that UIL Corporation's high-end estimate should be substituted for its illogical low-end value to establish the bottom of the zone of reasonableness. PATH argues that the Presiding Judge and the Commission rejected this approach as counter to the Commission's accepted DCF method, which requires a separate low and high estimate

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[89] *Duquesne*, 118 FERC ¶ 61,087 at P 73.

[90] PATH Answer at 8 (citations omitted).

[91] *Midwest Indep. Transmission Sys. Operator, Inc.*, 100 FERC ¶ 61,292, at P 12 (2002) (*Midwest ISO I*), *order denying reh'g*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 102 FERC ¶ 61,143 (2003) (*Midwest ISO II*), *on voluntary remand*, 106 FERC ¶ 61,302 (2004) (*Midwest ISO III*), *aff'd*, *Public Serv. Comm'n of Kentucky v. FERC*, 397 F.3d 1004 (D.C. Cir. 2005).

[92] *Opinion No. 489*, 117 FERC ¶ 61,129 at P 8.

for proxy firms. As the Commission concluded, "we agree with the presiding judge that having excluded UIL's low-end ROE, it would have been improper to then use UIL's high end ROE to establish the low-end ROE for the proxy group."[93] PATH states that contrary to protesters' contention, this does not require that *both* the low-end and the high-end estimates must be excluded if one is found to be illogical, only that they cannot be substituted for one another.

87. PATH states that protesters misrepresent the Commission's prior findings, contending that the Commission found that the median should be used rather than the midpoint. PATH states that this is incorrect. PATH argues that in *Midwest ISO III*, the Commission emphasized that the objective of its discussion was not to make any generic determination that would apply to other proceedings. PATH cites to *Midwest ISO III* at P 9-10, which states:

> As an initial matter, we emphasize that the primary question to be considered here is not what constitutes the best overall method for determining ROE generically (*i.e.*, the midpoint versus the median or mean); it is whether the use of the midpoint is most appropriate in this case.[94]

88. PATH states that contrary to ODEC's assertion, the Commission made no finding whatsoever that would reverse its clear preference for the midpoint in evaluating the ROE for individual electric utilities.

#### iv. Commission Determination

89. Since we have found that that the Project here satisfies the requirements of section 219, we are tasked with two remaining determinations on the ROE incentive; whether this incentive meets the nexus test, and whether this incentive fulfills the requirements of section 205.

90. We find that the Project satisfies the nexus test for an ROE in the high end of the zone of reasonableness.

91. First, we note that the Project is a baseline project in PJM's RTEP. The Project has far-reaching scope and regional benefits as a backbone transmission project that will relieve transmission constraints along a critical mid-Atlantic corridor. It also faces

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[93] PATH Answer at P 13 (*citing Opinion No. 489*, 117 FERC ¶ 61,129 at P 54).

[94] PATH Filing at 14.

significant risks related to the magnitude of the financial investment required[95] and the involvement of multiple entities and jurisdictions.[96] As described by PATH, the Project also faces significant siting issues such as the difficulty in obtaining timely approvals in various locations, which can be both protracted and challenging. PATH emphasizes that the Project requires the balancing of competing interests by state siting agencies.[97] The Project also presents a lead time which presents financial risks because a significant time period may pass before any costs are recovered and the extended time period exposes the Project potentially to additional regulatory, siting, cost increase, and other risks.[98] Additionally, in undertaking this significant capital-intensive project, PATH's ability to secure financing for transmission projects may be impacted as its borrowing needs increase overall. We find here that granting the ROE incentive conditioned on our section 205 determinations below, will encourage investment in a transmission project with substantial risks.

92. We turn to PATH's section 205 demonstration, and protesters' assertions that the resulting ROE is unjust and unreasonable.

93. A number of adjustments to PATH's proposed proxy group were proposed by several protesters in this proceeding. The Supreme Court has provided guidance in two often cited decisions regarding the range of allowed returns that may be permitted in a particular case. In *Bluefield*, the Court stated that the approved return should be "reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties."[99] In *Hope*, the Court provided additional guidance on this issue:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other

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[95] The Project is estimated to cost $1.8 billion. *See* PATH Filing at 12; Ex. No. PTH-100 at 15.

[96] Ex. No. PTH-100 at 33-34.

[97] *Id.*

[98] *Id.*

[99] 262 U.S. at 693.

> enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[100]

94. As both PATH and the protesters point out, the Commission has provided additional guidance on the development of a proxy group in *Opinion No. 445*, *Opinion No. 489*, and the *Midwest ISO* series of orders. In *Midwest ISO I*, the Commission accepted a proxy group of Midwest ISO transmission owners, in setting an ROE applicable to the participating transmission owners in the Midwest Independent Transmission System Operator, Inc. (Midwest ISO).[101] In *Opinion No. 489*, the Commission utilized a 10-company proxy group made up of northeast utility companies, *i.e.*, transmission owning entities doing business in the RTO at issue (ISO New England, Inc. (ISO-NE)), as well as in the broader, but interrelated RTO markets operated by PJM and the New York Independent System Operator, Inc. (New York ISO).

95. We find that PATH used the appropriate initial proxy group of entities within the interrelated RTO markets operated by PJM, ISO-NE and the New York ISO to begin its DCF analysis. PATH then applied the following screening criteria, consistent with this Commission precedent, as part of its analysis by excluding: (1) those utilities that are not currently paying cash dividends; (2) utilities that have announced a merger during the six-month period used to calculate the dividend yields; (3) utilities primarily operating as natural gas companies; and (4) utilities that do not have both an IBES growth rate and Value Line data.

96. However, while PATH states that it did apply a screen for risk, PATH's proxy group does not sufficiently screen for risk because it includes various companies in its proxy group whose corporate credit ratings are not comparable. Further, PATH has not sufficiently screened its proxy group for unsustainable growth rates. Finally, PATH has excluded certain low-end utilities' returns inconsistent with the Commission's policy on electric utilities. Therefore, PATH's final proxy group, as proposed, is unjust and unreasonable.

97. We agree with protesters that we must consider the proxy group consistent with *Hope*, *i.e.*, whether the proxy group is composed of companies with comparable risk to that of PATH. It is reasonable to use the proxy companies' corporate credit rating as a good measure of investment risk, since this rating considers both the financial risk and the business risk of the company.

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[100] 320 U.S. at 603.

[101] *See Midwest ISO I*, 100 FERC ¶ 61,292 at P 32.

98. As PATH notes, its parent companies' corporate credit ratings are BBB- (Allegheny) and BBB (AEP).[102] We will apply the following additional screening criteria to PATH's proxy group presented in Ex. No. PTH-402, consistent with Commission precedent: (1) corporate credit ratings of BBB- to BBB+ or the equivalent Moody's rating;[103] (2) elimination of companies with unsustainable growth rates;[104] and (3) exclusion of companies whose low-end return is at or below the cost of debt.[105]

99. Based on this, we exclude Dominion Resources, Consolidated Edison, NSTAR, and FPL Group, Inc. from the proxy group, because their corporate credit ratings are not within the "comparable risk" band outlined in *Opinion No. 445* and as detailed above.

100. We agree with protesters that the inclusion of PS Enterprise Group and Constellation Energy Group in this proxy group is inappropriate, consistent with the Commission's findings in the *RTO Rehearing Order*.[106] In that proceeding, we outlined that a 13.3 percent growth rate is not a sustainable growth rate over time and therefore does not meet threshold tests of economic logic. These companies' growth rates exceed that threshold established in the *RTO Rehearing Order*.[107] We disagree with protesters that PPL should be eliminated from the proxy group because of its growth rate. Based on the August 31 and September 28, 2007 data using Value Line and IBES,[108] PPL has a growth rate of 8 to 12 percent. While protesters rely upon the August 31 and September 28, 2007 data to support their own DCF analysis, they inexplicably recalculate PPL's growth rates using data from an entirely different time period.

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[102] Ex. No. PTH-400 at 37.

[103] *Opinion No. 445*, 92 FERC ¶ 61,070 at 61,264 (advocating the use of a proxy group of utilities with comparable bond ratings).

[104] *ISO New England, Inc.*, 109 FERC ¶ 61,147, at P 205 (2004).

[105] *Opinion No. 445*, 92 FERC ¶ 61,070 at 61,266; *Opinion No. 489*, 117 FERC ¶ 61,129 at P 54-60.

[106] 109 FERC ¶ 61,147 at P 205.

[107] Specifically, Ex. No. PTH-402 lists Constellation Energy Group's growth rate as 16 percent, Exelon Corporation's growth rate is 14 percent, and PS Enterprise Group's growth rate is 18 percent.

[108] Ex. No. PTH-402.

101. In both *Opinion No. 445* and *Opinion No. 489*, we found that a company whose ROE is lower than its own cost of debt should not be included in the proxy group.[109] While *Opinion No. 445* did not establish a bright line regarding how much of a rate differential would support the inclusion or exclusion of a company from the proxy group, *Opinion No. 489* established that such a determination would be made specific to the facts of each case. Here, PATH proposes to exclude one component of UIL Holdings, but not the other. Specifically, PATH proposes to exclude the low-end return of 6.7 percent of UIL Holdings, but leave in UIL Holdings high-end return of 16 percent. As a preliminary matter, removing only the low-end return of a single company included in a proxy group, but leaving in its high-end return could impose a bias resulting in a higher ROE, since the midpoint of any zone of reasonable returns is determined by using only the low-end and the high-end returns, and none of the returns in between.

102. Further, UIL Holdings' low-end return result is above the cost of debt. PATH provides speculative forecasting of this indexed cost of debt by using data from one year (2007) to forecast bond yields into 2012, in support of excluding the low-end return result of UIL Holdings. PATH's support is insufficient to establish that this low-end result should be removed. This flawed support is exacerbated by the fact that removing only the low-end return results in a bias. We will therefore include UIL Holdings in the proxy group. With our adjustments to PATH's proxy group on the basis of risk and growth rates, UIL Holdings low-end return of 6.7 percent sets the low end of the zone of reasonable returns for the entire proxy group. Likewise, UIL Holdings high-end return of 16 percent sets the high end of the zone of reasonable returns for the entire proxy group.

103. Based on this analysis, *supra*, we find that PATH's proxy group should include: American Electric Power Corporation, Central Vermont Public Service, DPL Inc., FirstEnergy Corporation Northeast Utilities, Pepco Holdings, UIL Holdings, and PPL Corporation, which establishes a zone of reasonable returns of 6.7 percent to 16 percent.

104. Based on this revised proxy group and the risks faced by the project, the Commission will grant PATH's request for an ROE of 14.3 percent, which is within the high end of the zone of reasonableness, but not at the high end of 16 percent. This ROE being granted herein is considered inclusive of the 50 basis point ROE incentive granted for RTO participation. Thus, we will not grant a 150 basis point adder onto a midpoint or median return. Therefore, protesters' concerns, whether the midpoint or median should

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[109] *Opinion No. 445*, 92 FERC ¶ 61,070 at 61,266.

be used, are moot. Further, by nature of the overall ROE being within the high end of the zone of reasonableness, but not at the high end, we have adjusted the ROE to reflect the total package of incentives requested herein.

105. Finally, despite our limiting PATH's proxy group, we emphasize that the 15-company proxy group PATH proposes here[110] is a good starting point for companies in PJM to use to develop an individual proxy that takes into account comparable risks. The exclusion of certain companies in this case does not preclude other companies in the region from proposing to use these excluded companies in developing a proxy group in the future, given comparable risk characteristics. To do so would disregard the mutable nature of the market data used in the screening criteria for the proxy group consistent with *Hope*. In other words, utilities' corporate credit ratings change over time. Utilities' growth rates change over time. What may not be sustainable or comparable at this point in time, may be comparable at a future date, by a different company.

### 4. Total Package

#### a. PATH's proposal

106. PATH states that the total package of incentives is tailored to address the demonstrable risks or challenges faced in construction of the Project for several reasons. First, PATH states that the recommended ROE of 14.3 percent is well below the upper end of the zone of reasonable returns, so there is no further need for a downward adjustment.[111] Second, PATH states that while inclusion of CWIP in rate base will impact PATH's credit rating, it will not have a measurable effect on overall risk, because it changes only the timing of the recovery, not the absolute amount of recovery. Third, while the opportunity to recover costs associated with plant that is abandoned moderates regulatory risk associated with new transmission investment, this reduction in investment risk is offset by the uncertainties that accompany a section 205 filing, which the Commission requires before abandoned plant costs can be recovered.[112] Finally, PATH states that while the Commission elected to reduce the ROE incentive for new

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[110] Specifically, American Electric Power, Central Vermont Public Service, Consolidated Edison, Constellation Energy Group, Dominion Resources, DPL, Inc., Exelon Corporation, FirstEnergy Corporation, FPL Group, Northeast Utilities, NSTAR, Pepco Holdings, PPL Corporation, PS Enterprise Group, and UIL Holdings.

[111] Ex. No. PTH-400 at 71.

[112] *Id.* at 71-72.

transmission investment from 150 basis points to 125 basis points in *Southern California Edison Co.*, there are important differences in the use of advanced technologies between these projects.[113]

### b. Protests

107. Protesters state that while they strongly support construction of new regional high voltage transmission facilities in PJM, they cannot endorse the significant quartet of incentives proposed by PATH.

108. Protesters state that the Commission should revisit the issue of whether the "incentive rate treatments such as the recovery of CWIP and pre-construction/pre-operating costs may result in a lowered risk assessment that would affect the need for an ROE rate incentive to compensate for that risk."[114] Protesters request that the Commission set the ROE incentive for hearing (exclusive of the 50 basis point adder for RTO participation), to determine whether it is just and reasonable in the context of the total package of incentives.[115]

109. Protesters request that the Commission adjust the ROE incentive to reflect the reduced risk effect of the total package of incentives in the event that the Commission does not set the appropriate level of ROE incentive for hearing. Protesters state that such an adjustment taking into account the total package of incentives would be consistent with the Commission's decision in *Southern California Edison Co.* Protesters request that the Commission limit the transmission incentive to not more than 50 basis points, plus the 50 basis points for RTO participation.

110. Protesters state that based upon the Commission's assumption that the inclusion of the Project as a baseline PJM RTEP project establishes a presumption of reliability/congestion relief benefits, the presumption that the Project provides such cost-effective benefits should not continue to apply if the Project exceeds its estimated costs or is delayed beyond the proposed 2012 in-service date. Protesters assert that reliability benefits diminish the longer the Project is delayed, and cost overruns offset any congestion benefits the Project might provide. Protesters state that in such circumstances, the predicate for granting incentives no longer holds true.

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[113] *Id.* at 72.

[114] ODEC Protest at 23 (*citing Allegheny II*, 118 FERC ¶ 61,042 at P 40; *AEP II*, 118 FERC ¶ 61,041 at P 32).

[115] ODEC Protest at 16.

111. Protesters argue that the coverage ratio analysis that PATH performs to demonstrate that it needed both the ROE incentive and the CWIP incentive combined, to maintain investment grade rating, does not take into consideration the parent companies' current investment-grade rating. Protesters state that PATH does not provide the underlying assumptions in its coverage ratio analysis, such as the assumed interest rate(s) used in the hypothetical capital structure, the assumed CWIP and plant in-service balances and resulting rate base for each year, and the overall weighted average rate of return (ROR), among other things. Protesters state that the filing to justify this combination of incentives, is devoid of work papers showing the calculations for taxes, assumed revenues and expenses. Protesters state that in addition to this, PATH does not provide any sensitivity analyses to show what the results would be if different ROEs were used. Further, when PATH reports S&P's ratings criteria for comparison purposes, it does so only with regards to criteria used for higher risk companies (with S&P's business risk profiles of 5 and higher). Protesters state that this choice does not reconcile with S&P's determination that typical business risk profiles for "large transmission systems and regulated distribution systems (the 'wires' business) business profile assessments tend to fall within the 1-4 range."[116]

112. ODEC states that with these assumptions corrected, and based upon PATH's testimony in its filing,[117] PATH would still be able to maintain its corporate credit rating if it were given both CWIP and an overall ROE of 10.2 percent (9.7 percent plus 50 basis points for RTO participation), because the corrected coverage ratio is 3.18, given an ROE of 10.2 percent. ODEC states that this falls squarely within the 2.4 to 3.5 range to garner a BBB rating, for a company with a high business risk profile of 5.[118]

113. JCA further argues that the nature of formula rates reduces risk to investors, and therefore the Commission should reduce the amount of any "new transmission" incentives sought by PATH as a result of being granted formula rates.

114. AMP-Ohio argues that during the early stages of this project, AMP-Ohio expressly offered to participate in the Project as a partial owner. AMP-Ohio states that its participation as a public power entity would have curtailed both risk and cost of AEP. AMP-Ohio on behalf of its public power members would have contributed funds most

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[116] *Id.* at 15 (*citing* S&P's Corporate Ratings Criteria publication under Power Companies).

[117] ODEC uses PATH's claimed 14.3 percent ROE, the requested 50/50 hypothetical capital structure, and a 7.89 percent cost of debt as presented in PATH's filing in Ex. Nos. PTH-200, PTH-300, and PTH-302.

[118] ODEC Protest at 13-15.

likely obtained through tax-exempt rates towards the Project and thus at a lower rate than AEP faces in the financial market. AMP-Ohio states that AEP's Senior Vice President for Transmission and witness here, Michael Heyeck, advised AMP-Ohio that AEP did not want it as a partner.

115. AMP-Ohio states that the Commission extolled the value of public power participation in Order No. 679.[119] Despite this, AEP not only failed to produce a transmission project with public power participation, it actively barred a public power entity from joining. AMP-Ohio states that if the Commission truly wishes to encourage public power participation, it would be sending exactly the wrong signal if it blesses the Project with every incentive yet devised.

### c. PATH's Answer

116. PATH asserts that formula rates were not identified as a form of incentive ratemaking in Order No. 679, and therefore, are not incentive rates, as protesters assert. PATH argues that protesters incorrectly assert that it failed to state its cash flow assumptions in the underlying cash flow analysis, noting pages 26-27 of Dr. Joenson's testimony that the cash flow analysis is based on the projected earnings of PATH during the construction period and the year when the plant is to go into service.

117. Further, PATH argues that while protesters criticize Dr. Joenson's cash flow analysis for not preparing sensitivity analyses to determine whether ROE levels other than the one requested would produce satisfactory coverage ratios, these protesters ignore the other two independent bases of support for the requested 14.3 percent ROE. Specifically, PATH asserts the other two forms of support were: (1) the analyses presented by Dr. Joenson and Dr. Avera of the project's risk and the nexus to the requested 150 basis point incentive adder, in light of the Commission precedent discussed in his testimony as well as in the filing's transmittal letter; and (2) the DCF analysis presented by Dr. Avera. PATH states that the absence of a sensitivity analysis does not detract from the basic conclusion that PATH has supported its request for a 14.3 percent incentive-based ROE, or, alternatively, a 150 basis point adder to the base ROE determined at hearing.

118. PATH states that parties incorrectly assert that Dr. Joenson should have used the S&P risk profiles of American Transmission Company and ITC Holdings Corp. in development of his coverage ratio, stating that these companies are not comparable to PATH because they hold operating assets that generate substantial cash flow, whereas PATH is a start-up company with no operating assets. PATH states that it has a greater degree of risk and is appropriately classified with companies with higher business risk

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[119] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

profiles. Further, PATH states that ODEC's calculation of cash flows, in developing a coverage ratio analysis[120] is inconsistent with how the financial community calculates coverage ratio analyses, and provide no meaningful information.

119. PATH answers that it did not "rebuff" AMP-Ohio's participation in PATH. PATH states that AEP did meet with AMP-Ohio, as AEP did with other potential investors, at the early stage of the planning process. PATH states that these negotiations occurred before the Project existed. PATH argues that to explain why the various alternative business arrangements did not materialize would necessarily include a full examination of all the discussions and the historical and economic context in which they occurred. PATH states that such a process would be both unproductive and inimical to the type of free and frank dialogue needed to develop such business arrangements, and the fact that such discussions did not lead to a business arrangement is not unusual.

### d. Commission Determination

120. As discussed above, we find that PATH has shown that, consistent with Order No. 679-A, the total package of incentives is tailored to address the demonstrable risks or challenges faced by PATH.[121] Consistent with Order No. 679, the Commission has, in prior cases, approved multiple rate incentives for particular projects.[122] This is consistent with our interpretation of FPA section 219 as authorizing the Commission to approve more than one incentive rate treatment for an applicant proposing a new transmission project, as long as each incentive is justified by a showing that it satisfies the requirements of FPA section 219 and that there is a nexus between the incentives being proposed and the investment being made. Here, as discussed above, PATH has explained why it is seeking each incentive and how each is relevant to the proposed Project. As discussed above, we find that PATH faces significant risks and challenges in constructing the Project. Thus, we find that PATH has shown a nexus for the total package of incentives.

121. We are not inclined to limit the incentives that we are approving in this order to a specific time period or to a total cost amount of the Project. In fact, the 14.3 percent ROE that we are granting reflects the risks relating to the costs and time constraints of

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[120] Specifically, Earnings Before Interest and Taxes/Interest ratios.

[121] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 21, 27.

[122] *See, e.g.*, *Allegheny*, 116 FERC ¶ 61,058 at P 60, 122 (approving ROE at the upper end of the zone of reasonableness and 100 percent abandoned plant recovery); *Duquesne*, 118 FERC ¶ 61,087 at P 55 (granting an enhanced ROE, 100 percent CWIP, and 100 percent abandoned plant recovery).

constructing the Project. As stated above, we have adjusted PATH's ROE to reflect the total package of incentives requested herein, by nature of it being within the high end of the zone of reasonable returns, but not at the high end of the zone.

122. We find that PATH has established a nexus between each incentive and the investments being made for the Project and has demonstrated that each incentive is appropriate under section 219. Thus, we believe that the overall package of incentives reflect the significant risks and challenges faced by PATH in constructing the Project. As discussed above, the Commission did consider the overall package of incentives when determining PATH's ROE.

123. Regarding AMP-Ohio's concern on encouraging public power participation, in Order No. 679, the Commission determined that it would not condition recovery of incentives on the type of business structure and stated that it will entertain appropriate requests for incentive ratemaking for investment in new transmission projects involving participation by public power entities.[123] In Order No. 679-A, the Commission further stated:

> While the Commission encourages public power participation, we will not require such participation as a condition of any proposed incentive rate treatment. As we state elsewhere in this order, the Commission cannot compel investment or <u>certain</u> types of investment. Our focus in this rule is to provide incentives that will facilitate voluntary investments by utilities. . . . In the context of a rule to provide rate incentives for the construction of new transmission and to encourage deployment of technologies to increase the capacity and efficiency of existing transmission facilities, we do not believe that mandating an opportunity for public power participation is necessary nor do we believe that failure to do so would be unduly discriminatory.[124]

### C. Proposed Formula Rate and Estimated Inputs

#### 1. Protests

124. Protesters raise issues not only with the formula rate, but also with the inputs that will flow through the formula rate. Protesters request that the Commission set PATH's

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[123] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 354.

[124] Order No. 679-A FERC Stats. & Regs. ¶ 31,236 at P 102 (emphasis in original).

formula rate request for hearing. Further, protesters request that the Commission not limit the issues set for hearing as PATH requests.

125. Protesters oppose PATH's inclusion of $7,078,915[125] in rate base as an unamortized regulatory asset related to pre-commercial expenses incurred but not included in CWIP prior to the proposed effective date of the rate. Protesters state that PATH fails to provide data in its filing that would allow interested parties to assess the type of costs that have been incurred and included in the regulatory asset as pre-commercial costs, and at what rates the AFUDC has been capitalized on those costs. Protesters state that the formula rate lacks transparency in this regard. Protesters request that the Commission require PATH to provide a comprehensive list of the pre-commercial costs along with a description of the activities leading to those costs and to provide work papers showing the development of the AFUDC rates applied to those costs.

126. In addition, ODEC argues that the Commission recently found in *TrAILCo* that pre-commercial costs that are capitalized in the depreciation expense sections of the formula should be amortized in Account 566,[126] and the utility should address all the necessary modifications in the hearing proceedings. ODEC requests that the Commission require PATH to address this issue in the hearing proceedings.

127. Protesters state that PATH has included a projection of $18,433,478 for CWIP in rate base without any support that would allow parties to assess whether the CWIP costs projected for the test year are legitimate and appropriately included in rate base.[127] Protesters request that PATH provide a detailed list of these projected costs.

128. AMP-Ohio requests that the Commission require PATH to use a 13-month average balance for these balances, consistent with its use of a 13-month average balance for plant-in-service.[128]

129. AMP-Ohio protests PATH's use of the "hoary" 1/8th rule for determining cash working capital. AMP-Ohio states that the Commission should require PATH to perform

[125] ODEC Protest at 34 (*citing* Ex. No. PTH-302, Line 38 and 155).

[126] Account 566, Miscellaneous Transmission Expense.

[127] ODEC Protest at 34.

[128] AMP-Ohio Protest at 14-15.

a lead-lag study to support any allowance for cash working capital because much of the revenue requirement is plant and therefore, real-estate tax related, which tends to have a very substantial lag in the payment of such taxes.

130. AMP-Ohio protests PATH's development of Post Employment Benefits other than Pensions (PBOPs), stating that line 195 of the PATH-WV formula for "Amount related to retired personnel" has an amount of $8.8 million. AMP-Ohio questions how a new stand-alone company that is not yet in operation can already have retired personnel.

131. AMP-Ohio argues that the formula rate template for PATH includes line items (lines 22 and 139) that provide an entry for accumulated depreciation of general and intangible plant. AMP-Ohio argues that Intangible plant is amortized, not depreciated, and Accumulated Amortization of Intangible Plant must be deducted from rate base. AMP-Ohio requests that the Commission require the formula rate template to be amended to show a separate line item for Accumulated Amortization of Intangible Plant.

132. Protesters state that PATH has filed 600 pages of evidence consisting of three different depreciation studies and depreciation-related testimony for the Project. Protesters state that there has been insufficient time to fully analyze the complex depreciation studies in the short amount of time allowed for interventions and protests, and requests that the Commission set this issue for hearing to allow the parties to assess the appropriateness of those rates.

133. Parties request that PATH be required to annually file with the Commission pursuant to section 205, its proposed changes in charges resulting from the formula rates. Protesters state that this approach ensures Congress' intent in enacting Part II of the FPA, that the Commission has plenary means to prevent the imposition of unjust and unreasonable rates by not awarding PATH excessive discretion in the inputs to those rates. Protesters state that the formula rate would still remain the "filed rate", and the scope of any investigation would not "open up" any formulae themselves, but rather, only the changed charges. Protesters state that if the Commission does not exercise its section 205 powers over the process, abuse is only more likely to occur.

134. Protesters state that PATH's proposal to post the Annual Update each year on or before October 15, gives customers little time between this posting, and the October 30 date when the customer meeting will be held to explain the formula rates and cost detail. Protesters request that the Commission grant the similar relief as it granted in *Xcel*, when the Commission required the utility "provide the estimated revenue requirement for the following calendar year by September 1."[129]

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[129] *Xcel*, 121 FERC ¶ 61,284 at P 70.

135. AMP-Ohio states that the effective two year delay in the pass-through or recovery of under or over-collected amounts at the FERC interest rate result in a perverse incentive for PATH to overstate its revenue requirements. AMP-Ohio states that this incentive to over-charge ratepayers in forecasted formula rates exists because any money PATH collects that it must ultimately refund, recovers a higher return when charged [through ROE] than the money that must be paid as interest [through the interest rate outlined in 18 C.F.R. § 35.19a] on any refunds that result from the true-up.

136. Protesters argue that PATH's proposal eliminates customer rights to challenge other aspects of the formula rates, including the projected costs, revenues, and credits. Further, ODEC protests PATH's protocols limiting any determination to whether costs are prudently incurred, and even then, only to "new costs", which suggests that as long as a description of a cost has been used before, it is no longer subject to a prudence review.

137. Protesters oppose several additional aspects of the protocols, stating that they limit customers' ability to challenge whether PATH had taken the correct number from its FERC Form No. 1, prohibit challenges on costs other than undefined new costs, prevent challenges regarding whether costs had been properly accounted for, fail to accommodate changes in the Commission's accounting policies that might modify the application of the formula rate, and fail to give interested parties sufficient time or review procedures on the Annual Update and true-up adjustment.[130] Finally, protesters state that the Protocols limit customers' ability to make a formal challenge, engrafting a statutory limitation on customers' rights to file under section 206, among other things.[131]

138. The Illinois Commerce Commission challenges the allocation of PATH's costs to Illinois ratepayers via Commonwealth Edison Company's (ComEd) membership in PJM. It asserts that the Project is not necessary for ComEd's zone, and therefore they do not benefit from these upgrades.

139. Separately, JCA states that it will require discovery and time to study and analyze the depreciation studies PATH has filed for its proposed facilities.

### 2. <u>PATH's Answer</u>

140. PATH argues that AMP-Ohio's criticism of PATH's use of the Commission's 1/8th policy for calculating a cash working capital allowance of $11.8 million is

[130] ODEC Protest at 42, 46-49.

[131] *Id.* at 43-45.

inconsistent with Commission policy which states in the absence of a reliable lead-lag study available on the record, utilities should apply the 45 day convention.[132]

141. PATH explains that the depreciation rates proposed by PATH are based on recent studies of service life and net salvage which have been approved by the West Virginia Public Service Commission for its parent companies. PATH states that because the facilities will be similar in nature to facilities already owned by its parent companies, it is reasonable to use depreciation rates based on live and net salvage percentages previously developed and approved for those utilities.

142. PATH states that AMP Ohio errs in its assumptions that PATH has included costs related to retired personnel in the PBOP entry at line 195 of Attachment 4, page 5 of the populated formula rate set forth in Ex. No. PTH-303. PATH states that the adjustment removes from the formula rates, rather than includes in the formula rates, the PBOPs associated with retired employees. PATH further notes that consistent with Commission policy, the PBOPs are a stated value, requiring any changes to be made pursuant to section 205.[133] PATH argues that the lines in the formula that AMP Ohio references on intangible plant remove the accumulated depreciation associated with both intangible and general plant. Nevertheless, PATH states that if the Commission so directs, it will change the description on these lines to "Intangible Plant Amortization."[134]

143. PATH argues that ODEC's suggestion that PATH's annual informational filings be treated as section 205 filings is illogical. PATH answers that informational filings do not change the rate, *i.e.*, the formula itself. PATH states that the Commission has previously rejected the argument that the formula rate itself carries a burden of proof under section 205 in informational filings, but rather, noting that the formula rate is the rate on file, not the inputs. PATH asserts that the formula rate should not be subject to protest and review as part of each annual update as ODEC urges. PATH requests that ODEC's position be rejected as fundamentally at odds with the Commission's policy on formula rates.

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[132] *See, e.g.*, *Trans-Elect NTD PATH 15, LLC*, 117 FERC ¶ 61,214 at P 32, 39-43 (holding that in the absence of a reliable lead-lag study approximating the utility's cash working capital needs or hardships that would justify the departure from the established formula, a utility should use the Commission's 45-day convention).

[133] PATH Answer at 24.

[134] *Id.* at 25.

144. PATH states that ODEC errs in its assertion that the formula rate protocols impose restrictions on the customers' section 206 filing rights. PATH states that the protocols impose no restrictions on the Commission or the customers' section 206 rights.

### 3. Commission Determination

145. We first address the formula rate and then the inputs to the formula rate. For the reasons discussed below, we will accept PATH's proposed formula rate,[135] effective March 1, 2008, as requested, subject to conditions and nominal suspension, and set the formula rate for hearing and settlement judge procedures. Our preliminary analysis of the components of PATH's proposed formula rate indicates that the proposed formula rate has not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful.

146. We will not limit the hearing proceeding as PATH requests except as to the ROE and the specific issues described further below.[136] Formula rates must contain enough specificity to operate without discretion in their implementation.[137] As PATH notes, the formula itself is the rate on file and will be updated on a regular basis to reflect actual costs. As such, there is no need, as ODEC requests, to file the formula under section 205 on an annual basis. A formula with adequate specificity coupled with timely available, transparent inputs to the formula rate satisfies the Commission's requirements. In addition, in the instant case, the proposed tariff provides that the Annual Update shall be subject to challenge and review in accordance with H-19B with respect to the accuracy of the data and consistency with the formula of the charges shown in the Annual Update.

147. With regard to the inputs to the formula rate, protesters have raised concerns with the estimates that form the basis for the 2008 rates which will not be available, under the protocols, for true-up until 2010, and will be trued-up at the section 35.19a interest rates rather than the allowed rate of return afforded PATH. PATH has little financial/operating history, has no FERC Form 1 upon which to rely, and as such is in the necessary position of estimating what its annual costs will be. Going forward, PATH has committed to making its estimates available October 15 of each year and has provided a process by

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[135] The issues set for hearing include: (1) the statement of the ATRR that will be included as Attachment H-19 of the PJM OATT; (2) the cost of service formula itself that provides detailed calculations of the annual revenue requirements (including worksheets); and (3) formula rate implementation protocols in Attachment B to the ATRR.

[136] The ROE will not be part of this hearing because we have made a summary finding on the ROE in this order.

[137] *Midwest Indep. Sys. Operator, Inc.*, 108 FERC ¶ 61,235, at P 68 (2004).

which customers, state commissions and other interested parties can review and submit challenges to specific items included in the formula.[138] That process is not available, however, for the estimates that form the basis for the 2008 rates contained in the instant application. As such, at the ordered hearing, we will allow protesters to seek additional support for the inputs included in PATH's application. We note, however, that forecasts are just that and encourage PATH and the parties to consider ways to update the 2008 rates earlier than 2010. We believe that reconciling estimates to actuals more quickly will largely address protesters' concerns and will allow PATH and parties to explore this at the hearing and settlement judge procedures ordered herein.

148. While we are setting these matters for a trial-type evidentiary hearing, we encourage the participants to make every effort to settle their disputes before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed, pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[139] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise, the Chief Judge will select a judge for this purpose.[140] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions.

149. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

150. We will make specific findings, and not set for hearing, the ROE and the following issues:

### a. Cost Allocation

151. The Illinois Commerce Commission raises concerns on cost allocation. For large transmission projects such as this, cost allocation is first vetted through the PJM stakeholder process and ultimately determined by PJM as an independent entity. The

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[138] PATH Filing at Att. H-19B, section 1; Ex. No. ATL-1.

[139] 18 C.F.R. § 385.603.

[140] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their background and experience (www.ferc.gov – click on Office of Administrative Law Judges).

revenue allocation responsibilities have been set by PJM in the RTEP. For transmission projects built as a result of the PJM RTEP process, cost allocation is not part of the individual transmission owner's incentive request or its rate filing, but rather, is filed by PJM.

152. PATH's cost allocation was filed by PJM in Docket No. ER07-1186-000, and accepted by the Commission.[141] Therefore, the Illinois Commerce Commission's protest is outside the scope of this proceeding, and is a collateral attack on the Commission's order in that proceeding.

**b. CWIP**

153. To address certain protesters concerns regarding the transparency of including CWIP in rate base, we will require PATH to include as a part of its annual filing and formula true up, a descriptive list of the costs included as CWIP in order to give all parties the opportunity to examine the prudence of such costs, consistent with the section 205 requirements for CWIP.

**c. Pre-Commercial Costs**

154. As ODEC argues, the Commission has previously stated that expensed pre-commercial costs appear to be appropriately recognized as a transmission operating expense in Account 566 which includes transmission expenses not included elsewhere. Accordingly, we will require PATH to amortize all pre-commercial costs related to the Project in Account 566. Additionally, in the hearing procedures set forth below, PATH shall propose all necessary modifications to its formula rate to include pre-commercial costs using Account 566.

**d. Accounting**

**i. Comparability of Financial Information**

155. Public utilities that receive a current return on CWIP and expense pre-commercial costs recover these costs in a different period than when they would ordinarily be charged to expense under the general requirements of the Commission's Uniform System of Accounts (USofA).[142] To promote comparability of financial information between

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[141] *PJM Interconnection, L.L.C.*, 121 FERC ¶ 61,034 (2007). The Illinois Commerce Commission was an intervenor in this proceeding.

[142] The USofA requires an AFUDC to be capitalized as a cost of a construction project and depreciated over the service life of the asset. The USofA also requires pre-
(continued...)

entities the Commission has required a specific accounting treatment or the use of footnote disclosures to recognize the economic effects of having CWIP in rate base and expensing pre-commercial costs. To comply with this requirement, PATH requests authorization to use footnote disclosures consistent with disclosures previously authorized by the Commission.[143]

156. The Commission will authorize PATH's operating companies[144] to provide footnote disclosures in the notes to the financial statements of their annual FERC Form No. 1 and their quarterly FERC Form No. 3-Q which: (1) fully explain the impact of the transmission rate incentives it receives insofar as the incentives provide for a deviation from the general requirements of the USofA; (2) include details of amounts not capitalized because of the transmission rate incentives for the current year, the previous two years, and the sum of all years; and (3) include a partial balance sheet consisting of the Assets and Other Debits section of the balance sheet to include the amounts not capitalized because of the transmission rate incentives.

### ii. Income Taxes

157. PATH-WV and PATH-Allegheny are limited liability companies and are not subject to federal taxation. Instead, the tax obligations incurred through their operations are reported on the tax returns of their corporate parents, AEP and Allegheny.[145] As such, PATH-WV and PATH-Allegheny propose not to record income taxes on their books. For ratemaking purposes, PATH-WV and PATH-Allegheny are treated as corporations and receive an income tax allowance for the tax liability ultimately paid by AEP and Allegheny. Therefore, we will require PATH-WV and PATH-Allegheny to maintain their books of account based on the Commission's Uniform System of Accounts

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commercial costs to be accumulated in Account 183, Preliminary Survey and Investigation Charges, before being transferred to CWIP and capitalized as a cost of the construction project.

[143] Ex. No. PTH-500 at P 14, 15 (citations omitted).

[144] PATH consists, in part, of two operating companies including PATH West Virginia Transmission Company, L.L.C. (PATH-WV), and PATH Allegheny Company, L.L.C. (PATH-Allegheny). These operating companies will be jurisdictional to the Commission and required to comply with the Commission's accounting and reporting regulations in 18 C.F.R. Parts 101 and 141.

[145] Ex. No. PTH-500 at 4-6.

as if it were a corporation, including the income tax accounting requirements of the Commission's USofA.[146]

### iii. Miscellaneous Cost of Service Issues

158. We deny AMP-Ohio's request to require PATH to perform a lead-lag study. In *Trans-Elect NTD Path 15, LLC*, the Administrative Law Judge held that long-established Commission policy provides that a company need not perform such a study, and may instead rely on the 45-day convention without further showing.[147] We held that the Administrative Law Judge was "correct" in finding that the Commission's policy is that: "in the absence of a reliable lead-lag study approximating the utility's cash working capital needs or hardships that would justify departure from the established formula, a utility should use the 45 day convention."[148] AMP-Ohio's protest in the initial proceeding did not make any assertion that there was a lead lag study available, or that the 45 day convention would produce unjust and unreasonable results.

159. We grant parties' request for an earlier posting of the Annual Update. We believe that customers should receive such information earlier than October 15 in order to allow sufficient time to review the information before the meeting on October 31. Therefore, we will require that PATH provide the estimated revenue requirement for the following calendar year by September 1. These information sharing procedures will provide customers sufficient opportunity to monitor whether PATH is implementing the rate formula correctly.

The Commission orders:

(A) PATH's requested incentive rate treatments are hereby granted, as discussed in the body of this order.

(B) PATH's proposed formula rate is hereby accepted for filing and suspended for a nominal period, to become effective March 1, 2008, as requested, and set for hearing, as discussed in the body of this order.

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[146] 18 C.F.R. Part 101, General Instructions No. 18, Comprehensive Interperiod Income Tax Allocation; and Text to Account 190, Accumulated Deferred Income Taxes, Account 236, Taxes Accrued, Account 281, Accumulated Deferred Income Taxes-Accelerated Amortization Property, Account 282, Accumulated Deferred Income Taxes-Other Property, and Account 283, Accumulated Deferred Income Taxes-Other.

[147] 117 FERC ¶ 61,214 at P 32, 39-43.

[148] *Id.* (citations omitted).

(C) PATH is hereby directed to submit a detailed report of pre-commercial costs as part of the evidentiary hearing proceedings ordered below, as discussed in the body of this order.

(D) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure and the regulations under the Federal Power Act (18 C.F.R. Chapter I), a public hearing shall be held concerning PATH's proposed formula rates. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (E) and (F) below.

(E) Pursuant to Rule 603 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2007), the Chief Administrative Law Judge is hereby directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(F) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and the Chief Judge on the status of the settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(G) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in this proceeding in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Commission's Rules of Practice and Procedure.

By the Commission. Commissioner Kelly concurring and dissenting in part with a separate statement attached.
Commissioner Wellinghoff dissenting in part with a separate statement to be issued at a later date.

( S E A L )

Nathaniel J. Davis, Sr.,
Deputy Secretary.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Potomac-Appalachian
Transmission Highline, L.L.C. Docket No. ER08-386-000

(Issued February 29, 2008)

Kelly, Commissioner, *concurring and dissenting in part*:

This order addresses, among other things, incentive rate authorization proposed by Potomac-Appalachian Transmission Highline, L.L.C. (PATH). The PATH project at issue in the instant proceeding is a modification of two projects presented by American Electric Power Inc. (AEP) and Allegheny Energy Inc (Allegheny).[1] Both of the previous projects were already approved for incentive treatment, including returns on equity (ROE) in the upper end of the zone of reasonableness. I fully supported granting incentive treatment for both projects because I believed them to be "excellent transmission projects," representing precisely the kind of projects to which the Commission should grant incentives, and I support granting incentives here.[2] With regard to ROE, PATH requests a 50 basis point adder to the authorized ROE in recognition of its participation in PJM, as well as approval of an ROE at the high end of the zone of reasonableness or, alternatively, approval of a 150 basis point adder to result in an overall ROE of 14.3 percent.

I dissent on a point of procedure. Rather than set the determination of PATH's ROE for evidentiary hearing, the Commission establishes an ROE directly in this order. I disagree with the majority's decision. Instead, I would have set the ROE determination for an evidentiary hearing, which heretofore has been the Commission's practice. Despite language in Order 679-A that indicates that the Commission will consider an up-front ROE determination where sufficient support has been presented in the application,[3] I do not believe that this is an appropriate means for arriving at a just and reasonable ROE. I note that the

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[1] *Allegheny Energy Inc.*, 116 FERC ¶ 61,058 (2006), *order on reh'g*, 118 FERC ¶ 61,042 (2007) and *Amer. Elec. Power Serv. Corp.*, 116 FERC ¶ 61,059 (2006) (*AEP I*), *order on reh'g*, 118 FERC ¶ 61,041 (2007).

[2] *See* my statements on *Allegheny Energy Inc.*, 118 FERC ¶ 61,042 (2007) (Kelly, Comm'r, concurring) and *Amer. Elec. Power Serv. Corp.*, 118 FERC ¶ 61,041 (2007) (Kelly, Comm'r, concurring).

[3] *Promoting Transmission Investment through Pricing Reform*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236, at P 70 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

majority, in establishing an up-front ROE in a Southern California Edison proceeding on transmission incentives, which is being issued concurrently with this order in Docket No. ER08-375-000, acknowledges that failure to provide for an evidentiary hearing is a departure from the Commission's common practice. In that case, the Commission establishes a paper hearing "in order to give all parties an opportunity to present evidence to rebut the proposed ROE determination."[4] I believe that a paper hearing is not an adequate substitute for an evidentiary proceeding before an Administrative Law Judge where parties have the opportunity for cross-examination, rebuttal, and oral argument. Further, the majority makes no attempt to distinguish between this proceeding and the Southern California Edison proceeding and explain why one proceeding requires a paper hearing and why one does not. I believe that such disparate treatment not only undermines the majority's basis for skipping directly to an ROE determination for the PATH project but also reinforces the notion that the Commission has adopted an ad hoc approach to granting transmission incentives in general.

More generally, I believe that the approach adopted in this order will encourage applicants to seek either an ROE identical to that of a previous applicant exhibiting similar characteristics or an ROE that is slightly higher. The result would be the granting of incentives based on previous applications rather than incentives "tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project."[5] I have previously noted that, in Order No. 679-A, the Commission discussed the care that must be taken in granting incentive ROEs. We said "[a]lthough the Commission has broad discretion to establish returns on equity anywhere within the zone of reasonableness, we must be careful in the manner in which we exercise this discretion."[6] I fail to see how the methodology adopted in this order to make an ROE determination has appropriately and reasonably exercised the discretion discussed in Order No. 679-A.

With regard to the instant proceeding, several parties assumed that the Commission would indeed set the ROE determination for hearing and thus appear to have not presented the full breadth of their views in their submitted comments. Given that the Commission's common practice has been to set such matters for hearing, whether in proceedings on incentives or otherwise, they can hardly be faulted for such an assumption. While arguing that the applicants' proposed proxy group did not ensure comparability, Old Dominion Electric Cooperative stated that it would

[4] *S. Cal. Edison Co.*, 122 FERC ¶ 61,187, at P 27 (2008).

[5] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 6.

[6] *Id.* P 7.

> leave to the development of testimony for presentation at hearing the selection of a proxy group that is comprised of companies that are truly comparable in risk to PATH and its service at issue here.[7]

The sufficiency of the record relies not only on evidence provided by an applicant but also by intervening parties. Based on the statement above, as well as requests for an evidentiary hearing from other parties,[8] I am not convinced that the record here accurately reflects views of all interested parties on the ROE issue. More generally, a Federal Power Act section 205[9] proceeding provides interested parties 21 days to comment, whereas the timing of an evidentiary hearing is more accommodating. Consistently determining ROEs in the absence of evidentiary hearings will require interested parties, some of which rely on outside expertise in order to participate, to meaningfully respond in 21 days. This would drastically alter the schedule for such proceedings, most probably deny the Commission a full and robust record on which to base its determination and, I fear, undermine the confidence of transmission users that we are setting incentive ROEs with the care and consideration that they deserve.

If the concern is over the pace of an evidentiary hearing, I see no reason why the Commission could not direct an expedited hearing process,[10] directed at specific facts, after having made preliminary determinations in the order setting those issues for hearing.

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[7] Old Dominion Electric Cooperative Jan. 19, 2008 Motion to Intervene, Protest and Request for Evidentiary Hearing, Docket No. ER08-386-000, at 25.

[8] *See, e.g.*, Joint Consumer Advocates Jan. 18, 2008 Motion to Intervene, Protest and Request for Hearing, Docket No. ER08-386-000, at 10; *see also* Virginia State Corporation Commission Jan. 17, 2008 Motion to Intervene and Comments, Docket No. ER08-386-000, at 3.

[9] 16 U.S.C. § 824d (2000 & Supp. V 2005).

[10] I note that the Commission could establish an expedited hearing procedure for these types of cases. For example, Commission procedural regulations already provide for fast track hearing procedures for expedited hearings of complaints before an administrative law judge. *See* 18 C.F.R. § 385.206 (2007). The Commission's Office of Administrative Law Judges has correspondingly adopted procedures to implement this fast track process that provide for hearings within as few as three days of the Commission order setting the hearing and an initial decision within as few as eight days. *See* FERC Office of Administrative Law Judges Policies and Procedures Manual, § 2.36, Attachment A (2008), *available at* www.ferc.gov/legal/admin-lit/time-sum.asp.

My intention is not to dissuade transmission investment with this statement, particularly investment that resembles the PATH project. This is an exemplary transmission project, given the scope of PATH's investment, the relief the project will provide to ratepayers, the cooperative efforts of AEP and Allegheny, as well as many other factors. Further, as I note above, I have eagerly supported the individual projects that were combined to create the PATH projects and I continue to support them. However, I am compelled to concur and dissent in part based on the majority's approach to determining the ROE, which I believe fails to accord all interested parties the process they are due and lacks the careful consideration necessary to set an ROE appropriate to these circumstances.

For these reasons, I respectfully concur and dissent in part from this order.

Suedeen G. Kelly

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 20**

**Responding Witness: William E. Avera**

Q-20. Refer to page 37 of the Avera Testimony and Schedule WEA-3. Explain why the logic FERC applied to returns for regulated firms at the federal level should apply to firms operating in open competitive markets.

A-20. The logic underlying Dr. Avera's evaluation of cost of equity estimates, which FERC has also recognized, is that extreme outliers that are unlikely to represent investors' expectations should be eliminated in interpreting the results of quantitative methods applied to estimate the cost of equity. This logic applies not just to regulated utilities – whether under state or federal jurisdiction – but also to non-utility firms.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 21**

**Responding Witness: William E. Avera**

Q-21. Refer to page 39 of the Avera Testimony and Schedule WEA-5.

a. Explain why it was necessary to weight the firms in the calculations as opposed to performing the calculations on an unweighted basis.

b. Explain how stock prices were used in calculating the dividend yield referenced in footnote (a). Were the March 27, 2008 closing prices used or were average stock prices used?

c. What were the IBES and the Value Line average growth rates and explain how the 10.9 percent average growth rate was calculated.

A-21. a. Dr. Avera used market value weighting to be consistent with the methodology underlying the S&P 500 Composite Index, which is constructed based on market-value weighting.

b. Stock prices were not used by Dr. Avera to arrive at the average dividend yield referenced on Schedule WEA-5; rather, the dividend yields were those reported by Value Line on March 27, 2008.

c. The IBES and the Value Line growth rates and the calculation of the 10.9 percent average growth rate are included in the attachment.

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 3M Company | MMM | 2.57 | 11.3 | 6.0 | 8.7 | 55,617.52 | 0.0058 | 0.0149 | 0.0502 |
| 2 | Abbott Labs. | ABT | 2.59 | 11.8 | 10.0 | 10.9 | 86,009.84 | 0.0090 | 0.0232 | 0.0978 |
| 3 | Abercrombie & Fitch | ANF | 0.91 | 15.8 | 13.5 | 14.7 | 6,642.91 | 0.0007 | 0.0006 | 0.0102 |
| 4 | Aetna Inc. | AET | 0.09 | 14.8 | 15.0 | 14.9 | 21,562.23 | 0.0022 | 0.0002 | 0.0335 |
| 5 | Aflac Inc. | AFL | 1.50 | 14.9 | 14.0 | 14.5 | 31,211.47 | 0.0033 | 0.0049 | 0.0471 |
| 6 | Air Products & Chem | APD | 1.69 | 14.9 | 16.0 | 15.5 | 19,330.34 | 0.0020 | 0.0034 | 0.0312 |
| 7 | Allegheny Energy | AYE | 1.24 | 21.3 | 16.0 | 18.7 | 8,063.36 | 0.0008 | 0.0010 | 0.0157 |
| 8 | Allegheny Techn. | ATI | 0.99 | 17.2 | 21.0 | 19.1 | 7,427.95 | 0.0008 | 0.0008 | 0.0148 |
| 9 | Allergan, Inc. | AGN | 0.36 | 16.8 | 15.5 | 16.2 | 17,281.65 | 0.0018 | 0.0006 | 0.0291 |
| 10 | Allstate Corp | ALL | 3.41 | 7.2 | 8.0 | 7.6 | 27,119.71 | 0.0028 | 0.0096 | 0.0215 |
| 11 | Altera Corp. | ALTR | 0.87 | 18.2 | 13.0 | 15.6 | 6,205.00 | 0.0006 | 0.0006 | 0.0101 |
| 12 | Altria Group | MO | 4.27 | 7.3 | 0.5 | 3.9 | 147,945.30 | 0.0154 | 0.0659 | 0.0602 |
| 13 | Ambac Fin'l Group | ABK | 4.18 | 13.0 | 4.0 | 8.5 | 680.38 | 0.0001 | 0.0003 | 0.0006 |
| 14 | Amer. Cap. Strategies | ACAS | 11.09 | 7.7 | 8.0 | 7.9 | 6,839.68 | 0.0007 | 0.0079 | 0.0056 |
| 15 | Amer. Elec. Power | AEP | 4.02 | 6.0 | 6.0 | 6.0 | 16,324.98 | 0.0017 | 0.0068 | 0.0102 |
| 16 | Amer. Express | AXP | 1.57 | 11.6 | 11.0 | 11.3 | 53,750.63 | 0.0056 | 0.0088 | 0.0634 |
| 17 | Amer. Int'l Group | AIG | 1.78 | 11.7 | 11.0 | 11.4 | 114,776.20 | 0.0120 | 0.0213 | 0.1359 |
| 18 | Ameren Corp. | AEE | 5.83 | 4.8 | 3.5 | 4.2 | 9,092.19 | 0.0009 | 0.0055 | 0.0039 |
| 19 | Ameriprise Fin'l | AMP | 1.11 | 10.5 | 9.5 | 10.0 | 12,343.89 | 0.0013 | 0.0014 | 0.0129 |
| 20 | Anadarko Petroleum | APC | 0.59 | 7.6 | 5.0 | 6.3 | 28,296.49 | 0.0030 | 0.0017 | 0.0186 |
| 21 | Analog Devices | ADI | 2.54 | 15.5 | 11.5 | 13.5 | 8,333.06 | 0.0009 | 0.0022 | 0.0117 |
| 22 | Anheuser-Busch | BUD | 2.87 | 8.2 | 7.5 | 7.9 | 33,771.18 | 0.0035 | 0.0101 | 0.0277 |
| 23 | Aon Corp. | AOC | 1.46 | 9.2 | 8.5 | 8.9 | 12,014.59 | 0.0013 | 0.0018 | 0.0111 |
| 24 | Apache Corp | APA | 0.56 | 9.6 | 4.0 | 6.8 | 35,842.71 | 0.0037 | 0.0021 | 0.0254 |
| 25 | Applied Materials | AMAT | 1.14 | 12.8 | 12.0 | 12.4 | 29,078.01 | 0.0030 | 0.0035 | 0.0376 |
| 26 | Archer Daniels Midl'd | ADM | 1.29 | 11.1 | 14.0 | 12.6 | 25,858.88 | 0.0027 | 0.0035 | 0.0339 |
| 27 | Ashland Inc | ASH | 2.35 | 10.0 | 2.5 | 6.3 | 2,944.29 | 0.0003 | 0.0007 | 0.0019 |
| 28 | AT&T Inc. | T | 4.34 | 11.1 | 13.0 | 12.1 | 222,704.60 | 0.0232 | 0.1008 | 0.2800 |
| 29 | Automatic Data Proc. | ADP | 2.83 | 14.2 | 10.5 | 12.4 | 21,351.33 | 0.0022 | 0.0063 | 0.0275 |
| 30 | Avery Dennison | AVY | 3.44 | 10.5 | 10.0 | 10.3 | 4,688.79 | 0.0005 | 0.0017 | 0.0050 |
| 31 | Avon Products | AVP | 2.02 | 11.9 | 16.0 | 14.0 | 16,983.97 | 0.0018 | 0.0036 | 0.0247 |
| 32 | Baker Hughes | BHI | 0.79 | 15.0 | 16.5 | 15.8 | 20,677.62 | 0.0022 | 0.0017 | 0.0340 |
| 33 | Ball Corp | BLL | 0.91 | 9.9 | 10.5 | 10.2 | 4,455.22 | 0.0005 | 0.0004 | 0.0047 |
| 34 | Bank of America | BAC | 6.12 | 8.9 | 6.0 | 7.5 | 185,726.80 | 0.0194 | 0.1186 | 0.1444 |
| 35 | Bank of New York Mellon | BK | 2.07 | 11.3 | 10.5 | 10.9 | 52,827.86 | 0.0055 | 0.0114 | 0.0601 |
| 36 | Bard (C.R.) | BCR | 0.60 | 14.3 | 13.5 | 13.9 | 10,143.79 | 0.0011 | 0.0006 | 0.0147 |
| 37 | Baxter Int'l Inc | BAX | 1.50 | 13.5 | 15.5 | 14.5 | 36,793.54 | 0.0038 | 0.0058 | 0.0557 |
| 38 | BB&T Corp. | BBT | 5.25 | 7.2 | 6.0 | 6.6 | 19,265.25 | 0.0020 | 0.0106 | 0.0133 |
| 39 | Bear Stearns | BSC | 21.48 | 10.5 | 5.5 | 8.0 | 672.33 | 0.0001 | 0.0015 | 0.0006 |
| 40 | Becton, Dickinson | BDX | 1.29 | 13.1 | 12.0 | 12.6 | 21,552.50 | 0.0022 | 0.0029 | 0.0282 |
| 41 | Bemis Co. | BMS | 3.60 | 6.0 | 5.0 | 5.5 | 2,456.66 | 0.0003 | 0.0009 | 0.0014 |
| 42 | Best Buy Co. | BBY | 1.23 | 15.1 | 13.0 | 14.1 | 17,790.32 | 0.0019 | 0.0023 | 0.0261 |
| 43 | BJ Services | BJS | 0.83 | 10.0 | 5.0 | 7.5 | 7,095.90 | 0.0007 | 0.0006 | 0.0056 |
| 44 | Black & Decker | BDK | 2.50 | 6.7 | 5.5 | 6.1 | 4,200.48 | 0.0004 | 0.0011 | 0.0027 |
| 45 | Block (H&R) | HRB | 2.70 | 11.7 | 3.5 | 7.6 | 6,851.74 | 0.0007 | 0.0019 | 0.0054 |
| 46 | Boeing | BA | 2.14 | 13.8 | 15.5 | 14.7 | 55,103.74 | 0.0057 | 0.0123 | 0.0842 |
| 47 | Bristol-Myers Squibb | BMY | 5.78 | 11.3 | 11.5 | 11.4 | 42,477.64 | 0.0044 | 0.0256 | 0.0505 |
| 48 | Brunswick Corp. | BC | 3.45 | 11.0 | 3.5 | 7.3 | 1,530.91 | 0.0002 | 0.0006 | 0.0012 |
| 49 | Burlington Northern | BNI | 1.40 | 14.1 | 12.0 | 13.1 | 31,853.16 | 0.0033 | 0.0047 | 0.0434 |
| 50 | C.H. Robinson | CHRW | 1.60 | 18.0 | 15.5 | 16.8 | 9,431.47 | 0.0010 | 0.0016 | 0.0165 |
| 51 | CA, Inc. | CA | 0.72 | 11.7 | 33.5 | 22.6 | 11,395.01 | 0.0012 | 0.0009 | 0.0269 |
| 52 | Campbell Soup | CPB | 2.64 | 7.2 | 8.0 | 7.6 | 12,621.42 | 0.0013 | 0.0035 | 0.0100 |
| 53 | Capital One Fin'l | COF | 2.82 | 12.1 | 5.0 | 8.6 | 20,523.78 | 0.0021 | 0.0060 | 0.0183 |
| 54 | Cardinal Health | CAH | 0.91 | 13.9 | 12.5 | 13.2 | 18,816.25 | 0.0020 | 0.0018 | 0.0259 |
| 55 | Caterpillar Inc. | CAT | 1.95 | 12.3 | 14.5 | 13.4 | 46,946.57 | 0.0049 | 0.0096 | 0.0656 |
| 56 | CBS Corp. 'B' | CBS | 4.31 | 7.1 | 7.0 | 7.1 | 15,879.30 | 0.0017 | 0.0071 | 0.0117 |
| 57 | CenterPoint Energy | CNP | 5.16 | 12.5 | 6.0 | 9.3 | 4,569.69 | 0.0005 | 0.0025 | 0.0044 |
| 58 | CenturyTel Inc. | CTL | 0.80 | 3.9 | (0.5) | 1.7 | 3,664.83 | 0.0004 | 0.0003 | 0.0006 |
| 59 | Chesapeake Energy | CHK | 0.61 | 18.3 | 5.0 | 11.7 | 20,981.10 | 0.0022 | 0.0013 | 0.0255 |
| 60 | Chevron Corp. | CVX | 2.79 | 7.3 | 5.5 | 6.4 | 175,693.00 | 0.0183 | 0.0511 | 0.1173 |
| 61 | Chubb Corp. | CB | 2.64 | 9.5 | 4.5 | 7.0 | 19,200.56 | 0.0020 | 0.0053 | 0.0140 |
| 62 | CIGNA Corp. | CI | 0.10 | 12.3 | 12.5 | 12.4 | 11,120.97 | 0.0012 | 0.0001 | 0.0144 |
| 63 | Cintas Corp. | CTAS | 1.60 | 10.7 | 8.5 | 9.6 | 4,430.51 | 0.0005 | 0.0007 | 0.0044 |
| 64 | Circuit City Stores | CC | 3.65 | 11.1 | (3.0) | 4.1 | 737.49 | 0.0001 | 0.0003 | 0.0003 |

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 65 | CIT Group | CIT | 10.38 | 9.8 | 5.0 | 7.4 | 1,826.03 | 0.0002 | 0.0020 | 0.0014 |
| 66 | Citizens Communic. | CZN | 9.24 | 3.9 | 6.0 | 5.0 | 3,546.24 | 0.0004 | 0.0034 | 0.0018 |
| 67 | Clear Channel | CCU | 2.17 | 7.8 | 12.0 | 9.9 | 17,247.91 | 0.0018 | 0.0039 | 0.0178 |
| 68 | CME Group | CME | 0.98 | 26.3 | 22.0 | 24.2 | 25,096.71 | 0.0026 | 0.0026 | 0.0632 |
| 69 | CMS Energy Corp. | CMS | 2.60 | 5.2 | 11.0 | 8.1 | 3,113.77 | 0.0003 | 0.0008 | 0.0026 |
| 70 | Coca-Cola | KO | 2.49 | 9.6 | 9.0 | 9.3 | 140,880.30 | 0.0147 | 0.0366 | 0.1367 |
| 71 | Comerica Inc | CMA | 6.68 | 4.8 | 1.5 | 3.2 | 5,929.03 | 0.0006 | 0.0041 | 0.0019 |
| 72 | Commerce Bancorp NJ | CBH | 1.43 | 10.5 | 12.0 | 11.3 | 7,039.43 | 0.0007 | 0.0011 | 0.0083 |
| 73 | ConAgra Foods | CAG | 3.41 | 8.2 | 10.5 | 9.4 | 10,849.43 | 0.0011 | 0.0039 | 0.0106 |
| 74 | ConocoPhillips | COP | 2.51 | 9.5 | 0.5 | 5.0 | 117,590.10 | 0.0123 | 0.0308 | 0.0613 |
| 75 | CONSOL Energy | CNX | 0.62 | 14.9 | 24.0 | 19.5 | 11,635.99 | 0.0012 | 0.0008 | 0.0236 |
| 76 | Consol. Edison | ED | 5.73 | 3.4 | 4.5 | 4.0 | 11,069.63 | 0.0012 | 0.0066 | 0.0046 |
| 77 | Constellation Energy | CEG | 2.28 | 16.5 | 13.5 | 15.0 | 15,153.17 | 0.0016 | 0.0036 | 0.0237 |
| 78 | Cooper Inds. | CBE | 2.67 | 13.3 | 12.0 | 12.7 | 6,614.96 | 0.0007 | 0.0018 | 0.0087 |
| 79 | Corning Inc. | GLW | 0.83 | 16.5 | 16.0 | 16.3 | 37,584.96 | 0.0039 | 0.0033 | 0.0637 |
| 80 | Costco Wholesale | COST | 0.92 | 13.4 | 14.0 | 13.7 | 27,585.29 | 0.0029 | 0.0026 | 0.0394 |
| 81 | CSX Corp. | CSX | 1.32 | 17.2 | 16.5 | 16.9 | 22,927.80 | 0.0024 | 0.0032 | 0.0403 |
| 82 | Cummins Inc. | CMI | 1.02 | 20.7 | 12.5 | 16.6 | 10,018.05 | 0.0010 | 0.0011 | 0.0173 |
| 83 | CVS Caremark Corp | CVS | 0.60 | 17.0 | 13.5 | 15.3 | 57,242.81 | 0.0060 | 0.0036 | 0.0911 |
| 84 | Danaher Corp. | DHR | 0.16 | 13.5 | 13.5 | 13.5 | 23,711.23 | 0.0025 | 0.0004 | 0.0334 |
| 85 | Darden Restaurants | DRI | 2.10 | 12.4 | 12.5 | 12.5 | 4,921.70 | 0.0005 | 0.0011 | 0.0064 |
| 86 | Deere & Co. | DE | 1.26 | 11.4 | 9.5 | 10.5 | 34,547.05 | 0.0036 | 0.0045 | 0.0377 |
| 87 | Devon Energy | DVN | 0.67 | 9.4 | 6.0 | 7.7 | 42,820.06 | 0.0045 | 0.0030 | 0.0344 |
| 88 | Dillard's, Inc. | DDS | 0.87 | 6.0 | 5.5 | 5.8 | 1,380.05 | 0.0001 | 0.0001 | 0.0008 |
| 89 | Disney (Walt) | DIS | 1.10 | 13.4 | 14.0 | 13.7 | 61,598.90 | 0.0064 | 0.0071 | 0.0880 |
| 90 | Dominion Resources | D | 3.88 | 8.3 | 9.5 | 8.9 | 23,472.00 | 0.0024 | 0.0095 | 0.0218 |
| 91 | Donnelley (R.R) & Sons | RRD | 3.59 | 10.5 | 11.5 | 11.0 | 6,293.00 | 0.0007 | 0.0024 | 0.0072 |
| 92 | Dover Corp. | DOV | 1.95 | 15.3 | 12.0 | 13.7 | 10,030.94 | 0.0010 | 0.0020 | 0.0143 |
| 93 | Dow Chemical | DOW | 4.61 | 24.5 | (1.5) | 11.5 | 34,304.55 | 0.0036 | 0.0165 | 0.0412 |
| 94 | DTE Energy | DTE | 5.41 | 5.0 | 4.5 | 4.8 | 6,419.19 | 0.0007 | 0.0036 | 0.0032 |
| 95 | Du Pont | DD | 3.61 | 7.9 | 8.0 | 8.0 | 44,828.70 | 0.0047 | 0.0169 | 0.0372 |
| 96 | Eastman Chemical | EMN | 2.86 | 6.5 | 7.5 | 7.0 | 4,976.50 | 0.0005 | 0.0015 | 0.0036 |
| 97 | Eastman Kodak | EK | 2.99 | 4.5 | 7.5 | 6.0 | 4,812.48 | 0.0005 | 0.0015 | 0.0030 |
| 98 | Eaton Corp | ETN | 2.48 | 13.1 | 12.0 | 12.6 | 11,736.90 | 0.0012 | 0.0030 | 0.0154 |
| 99 | Ecolab Inc. | ECL | 1.20 | 14.0 | 13.0 | 13.5 | 10,634.48 | 0.0011 | 0.0013 | 0.0150 |
| 100 | Edison Int'l | EIX | 2.51 | 8.9 | 6.5 | 7.7 | 15,867.00 | 0.0017 | 0.0042 | 0.0127 |
| 101 | El Paso Corp. | EP | 1.05 | 10.6 | 27.0 | 18.8 | 10,718.25 | 0.0011 | 0.0012 | 0.0210 |
| 102 | Electronic Data Sys | EDS | 1.19 | 11.0 | 28.0 | 19.5 | 8,580.25 | 0.0009 | 0.0011 | 0.0175 |
| 103 | Emerson Electric | EMR | 2.45 | 12.8 | 13.0 | 12.9 | 38,649.45 | 0.0040 | 0.0099 | 0.0520 |
| 104 | ENSCO Int'l | ESV | 0.17 | 21.6 | 21.0 | 21.3 | 8,769.49 | 0.0009 | 0.0002 | 0.0195 |
| 105 | Entergy Corp. | ETR | 2.84 | 12.4 | 7.5 | 10.0 | 20,383.82 | 0.0021 | 0.0060 | 0.0212 |
| 106 | EOG Resources | EOG | 0.43 | 8.5 | 7.5 | 8.0 | 27,597.31 | 0.0029 | 0.0012 | 0.0230 |
| 107 | Equifax, Inc. | EFX | 0.46 | 11.3 | 10.5 | 10.9 | 4,705.32 | 0.0005 | 0.0002 | 0.0054 |
| 108 | Exelon Corp. | EXC | 2.49 | 10.1 | 9.0 | 9.6 | 53,064.00 | 0.0055 | 0.0138 | 0.0529 |
| 109 | Expeditors Int'l | EXPD | 0.63 | 17.9 | 16.0 | 17.0 | 9,403.73 | 0.0010 | 0.0006 | 0.0166 |
| 110 | Exxon Mobil Corp | XOM | 1.65 | 6.8 | 8.0 | 7.4 | 457,470.00 | 0.0477 | 0.0787 | 0.3532 |
| 111 | Family Dollar Stores | FDO | 2.44 | 11.1 | 16.5 | 13.8 | 2,880.80 | 0.0003 | 0.0007 | 0.0041 |
| 112 | Fannie Mae | FNM | 4.08 | 10.5 | (2.0) | 4.3 | 33,343.41 | 0.0035 | 0.0142 | 0.0148 |
| 113 | Federated Investors | FII | 2.12 | 12.3 | 10.5 | 11.4 | 4,038.48 | 0.0004 | 0.0009 | 0.0048 |
| 114 | FedEx Corp. | FDX | 0.46 | 13.1 | 9.5 | 11.3 | 26,889.18 | 0.0028 | 0.0013 | 0.0317 |
| 115 | Fifth Third Bancorp | FITB | 7.54 | 7.1 | 7.0 | 7.1 | 12,437.87 | 0.0013 | 0.0098 | 0.0091 |
| 116 | First Horizon National | FHN | 4.66 | 6.5 | 11.0 | 8.8 | 2,169.70 | 0.0002 | 0.0011 | 0.0020 |
| 117 | FirstEnergy Corp. | FE | 3.17 | 8.5 | 8.5 | 8.5 | 21,192.13 | 0.0022 | 0.0070 | 0.0188 |
| 118 | Fluor Corp. | FLR | 0.76 | 16.4 | 21.0 | 18.7 | 11,628.87 | 0.0012 | 0.0009 | 0.0227 |
| 119 | Fortune Brands | FO | 2.55 | 9.4 | 6.0 | 7.7 | 10,145.51 | 0.0011 | 0.0027 | 0.0082 |
| 120 | FPL Group | FPL | 2.92 | 9.8 | 9.5 | 9.7 | 24,778.78 | 0.0026 | 0.0075 | 0.0249 |
| 121 | Franklin Resources | BEN | 0.81 | 12.0 | 15.0 | 13.5 | 23,766.73 | 0.0025 | 0.0020 | 0.0335 |
| 122 | Freddie Mac | FRE | 3.07 | 9.8 | (1.5) | 4.2 | 21,543.66 | 0.0022 | 0.0069 | 0.0093 |
| 123 | Freep't-McMoRan C&G | FCX | 2.01 | 64.0 | 9.0 | 36.5 | 33,264.56 | 0.0035 | 0.0070 | 0.1267 |
| 124 | Gannett Co. | GCI | 5.29 | 2.5 | 3.5 | 3.0 | 7,023.48 | 0.0007 | 0.0039 | 0.0022 |
| 125 | Gap (The), Inc. | GPS | 1.50 | 12.3 | 8.0 | 10.2 | 16,262.57 | 0.0017 | 0.0025 | 0.0172 |
| 126 | Gen'l Dynamics | GD | 1.63 | 9.9 | 11.0 | 10.5 | 34,604.84 | 0.0036 | 0.0059 | 0.0377 |
| 127 | Gen'l Electric | GE | 3.31 | 11.0 | 11.0 | 11.0 | 378,881.80 | 0.0395 | 0.1308 | 0.4348 |
| 128 | Gen'l Mills | GIS | 2.66 | 8.6 | 8.5 | 8.6 | 20,200.32 | 0.0021 | 0.0056 | 0.0180 |

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 129 | Gen'l Motors | GM | 5.13 | 6.5 | 18.5 | 12.5 | 11,038.15 | 0.0012 | 0.0059 | 0.0144 |
| 130 | Genuine Parts | GPC | 3.85 | 9.3 | 8.0 | 8.7 | 6,730.61 | 0.0007 | 0.0027 | 0.0061 |
| 131 | Genworth Fin'l | GNW | 1.72 | 10.1 | 12.0 | 11.1 | 10,215.53 | 0.0011 | 0.0018 | 0.0118 |
| 132 | Goldman Sachs | GS | 0.78 | 11.6 | 15.5 | 13.6 | 71,411.91 | 0.0075 | 0.0058 | 0.1009 |
| 133 | Goodrich Corp. | GR | 1.55 | 16.0 | 18.5 | 17.3 | 7,277.72 | 0.0008 | 0.0012 | 0.0131 |
| 134 | Grainger (W.W.) | GWW | 1.79 | 13.1 | 14.5 | 13.8 | 6,201.64 | 0.0006 | 0.0012 | 0.0089 |
| 135 | Halliburton Co. | HAL | 0.99 | 14.3 | 17.0 | 15.7 | 31,882.40 | 0.0033 | 0.0033 | 0.0521 |
| 136 | Harley-Davidson | HOG | 3.14 | 11.5 | 11.5 | 11.5 | 9,231.09 | 0.0010 | 0.0030 | 0.0111 |
| 137 | Harman Int'l | HAR | 0.11 | 19.5 | 13.5 | 16.5 | 2,702.28 | 0.0003 | 0.0000 | 0.0047 |
| 138 | Hartford Fin'l Svcs. | HIG | 2.85 | 10.5 | 6.5 | 8.5 | 23,340.91 | 0.0024 | 0.0069 | 0.0207 |
| 139 | Hasbro, Inc. | HAS | 2.89 | 9.9 | 10.5 | 10.2 | 4,146.97 | 0.0004 | 0.0013 | 0.0044 |
| 140 | Heinz (H.J.) | HNZ | 3.37 | 8.0 | 8.0 | 8.0 | 14,228.98 | 0.0015 | 0.0050 | 0.0119 |
| 141 | Hershey Co. | HSY | 3.13 | 7.6 | 3.5 | 5.6 | 8,623.32 | 0.0009 | 0.0028 | 0.0050 |
| 142 | Hess Corp | HES | 0.44 | 14.0 | 9.5 | 11.8 | 29,025.14 | 0.0030 | 0.0013 | 0.0356 |
| 143 | Hewlett-Packard | HPQ | 0.69 | 15.0 | 16.5 | 15.8 | 119,970.00 | 0.0125 | 0.0086 | 0.1971 |
| 144 | Home Depot | HD | 3.21 | 10.8 | 4.5 | 7.7 | 47,365.28 | 0.0049 | 0.0159 | 0.0378 |
| 145 | Honeywell Int'l | HON | 2.03 | 12.6 | 15.5 | 14.1 | 40,542.09 | 0.0042 | 0.0086 | 0.0594 |
| 146 | Horton D.R. | DHI | 3.83 | 11.0 | (3.0) | 4.0 | 4,938.82 | 0.0005 | 0.0020 | 0.0021 |
| 147 | Hudson City Bancorp | HCBK | 1.97 | 14.5 | 15.0 | 14.8 | 9,484.63 | 0.0010 | 0.0019 | 0.0146 |
| 148 | Huntington Bancshs | HBAN | 9.43 | 5.8 | 8.0 | 6.9 | 4,116.77 | 0.0004 | 0.0041 | 0.0030 |
| 149 | Illinois Tool Works | ITW | 2.32 | 11.4 | 11.5 | 11.5 | 26,283.90 | 0.0027 | 0.0064 | 0.0314 |
| 150 | IMS Health | RX | 0.57 | 12.1 | 11.5 | 11.8 | 4,122.31 | 0.0004 | 0.0002 | 0.0051 |
| 151 | Ingersoll-Rand | IR | 1.67 | 14.0 | 11.0 | 12.5 | 11,717.13 | 0.0012 | 0.0020 | 0.0153 |
| 152 | Integrys Energy | TEG | 5.88 | 6.7 | 2.5 | 4.6 | 3,481.11 | 0.0004 | 0.0021 | 0.0017 |
| 153 | Intel Corp | INTC | 2.35 | 14.9 | 10.0 | 12.5 | 126,954.80 | 0.0132 | 0.0311 | 0.1649 |
| 154 | Int'l Business Mach. | IBM | 1.35 | 10.3 | 13.5 | 11.9 | 163,914.70 | 0.0171 | 0.0231 | 0.2035 |
| 155 | Int'l Game Tech. | IGT | 1.24 | 13.1 | 17.5 | 15.3 | 14,210.48 | 0.0015 | 0.0018 | 0.0227 |
| 156 | Int'l Paper | IP | 3.75 | 5.0 | 17.0 | 11.0 | 13,169.25 | 0.0014 | 0.0052 | 0.0151 |
| 157 | ITT Corp | ITT | 1.33 | 13.0 | 14.0 | 13.5 | 9,564.02 | 0.0010 | 0.0013 | 0.0135 |
| 158 | Jabil Circuit | JBL | 2.42 | 20.7 | 11.5 | 16.1 | 2,426.37 | 0.0003 | 0.0006 | 0.0041 |
| 159 | Janus Capital Group | JNS | 0.17 | 21.0 | 22.0 | 21.5 | 4,099.12 | 0.0004 | 0.0001 | 0.0092 |
| 160 | Johnson & Johnson | JNJ | 2.54 | 7.5 | 8.0 | 7.8 | 185,693.80 | 0.0194 | 0.0492 | 0.1501 |
| 161 | Jones Apparel Group | JNY | 3.96 | 9.3 | (1.5) | 3.9 | 1,240.08 | 0.0001 | 0.0005 | 0.0005 |
| 162 | JPMorgan Chase | JPM | 3.31 | 7.5 | 9.5 | 8.5 | 154,404.50 | 0.0161 | 0.0533 | 0.1369 |
| 163 | KB Home | KBH | 3.96 | 11.0 | (14.5) | (1.8) | 1,953.13 | 0.0002 | 0.0008 | (0.0004) |
| 164 | Kellogg | K | 2.40 | 9.1 | 9.5 | 9.3 | 20,338.28 | 0.0021 | 0.0051 | 0.0197 |
| 165 | KeyCorp | KEY | 6.39 | 5.5 | 3.5 | 4.5 | 9,122.98 | 0.0010 | 0.0061 | 0.0043 |
| 166 | Kimberly-Clark | KMB | 3.57 | 7.5 | 6.5 | 7.0 | 27,345.87 | 0.0029 | 0.0102 | 0.0200 |
| 167 | KLA-Tencor | KLAC | 1.67 | 14.3 | 10.0 | 12.2 | 6,452.99 | 0.0007 | 0.0011 | 0.0082 |
| 168 | Kraft Foods | KFT | 3.47 | 7.1 | 5.5 | 6.3 | 48,195.13 | 0.0050 | 0.0174 | 0.0317 |
| 169 | Kroger Co | KR | 1.42 | 10.7 | 12.5 | 11.6 | 17,094.20 | 0.0018 | 0.0025 | 0.0207 |
| 170 | L-3 Communic. Hldgs. | LLL | 1.12 | 21.1 | 11.0 | 16.1 | 13,093.02 | 0.0014 | 0.0015 | 0.0219 |
| 171 | Lauder (Estee) | EL | 1.21 | 12.0 | 7.5 | 9.8 | 8,766.20 | 0.0009 | 0.0011 | 0.0089 |
| 172 | Legg Mason | LM | 1.72 | 11.2 | 9.5 | 10.4 | 7,541.72 | 0.0008 | 0.0014 | 0.0081 |
| 173 | Leggett & Platt | LEG | 6.41 | 7.4 | 7.0 | 7.2 | 2,633.41 | 0.0003 | 0.0018 | 0.0020 |
| 174 | Lehman Bros. Holdings | LEH | 1.40 | 12.0 | 9.0 | 10.5 | 25,876.30 | 0.0027 | 0.0038 | 0.0283 |
| 175 | Lilly (Eli) | LLY | 3.77 | 7.3 | 7.0 | 7.2 | 56,534.16 | 0.0059 | 0.0222 | 0.0422 |
| 176 | Limited Brands | LTD | 3.50 | 12.7 | 7.5 | 10.1 | 6,101.84 | 0.0006 | 0.0022 | 0.0064 |
| 177 | Lincoln Nat'l Corp. | LNC | 3.12 | 11.5 | 10.0 | 10.8 | 14,308.44 | 0.0015 | 0.0047 | 0.0160 |
| 178 | Linear Technology | LLTC | 2.70 | 16.3 | 17.0 | 16.7 | 6,970.16 | 0.0007 | 0.0020 | 0.0121 |
| 179 | Liz Claiborne | LIZ | 1.15 | 10.0 | 0.5 | 5.3 | 1,939.41 | 0.0002 | 0.0002 | 0.0011 |
| 180 | Lockheed Martin | LMT | 1.68 | 11.6 | 12.5 | 12.1 | 40,920.45 | 0.0043 | 0.0072 | 0.0514 |
| 181 | Lowe's Cos. | LOW | 1.38 | 12.9 | 11.0 | 12.0 | 34,148.10 | 0.0036 | 0.0049 | 0.0426 |
| 182 | M&T Bank Corp | MTB | 3.24 | 8.8 | 7.0 | 7.9 | 9,226.20 | 0.0010 | 0.0031 | 0.0076 |
| 183 | Manitowoc Co. | MTW | 0.21 | 35.5 | 35.0 | 35.3 | 4,830.54 | 0.0005 | 0.0001 | 0.0178 |
| 184 | Marathon Oil Corp. | MRO | 2.06 | 11.1 | 8.0 | 9.6 | 33,029.20 | 0.0034 | 0.0071 | 0.0329 |
| 185 | Marriott Int'l | MAR | 0.87 | 13.6 | 14.5 | 14.0 | 12,621.63 | 0.0013 | 0.0011 | 0.0185 |
| 186 | Marsh & McLennan | MMC | 3.15 | 7.5 | 12.0 | 9.8 | 13,201.45 | 0.0014 | 0.0043 | 0.0134 |
| 187 | Marshall & Ilsley | MI | 4.96 | 8.0 | 1.0 | 4.5 | 6,679.80 | 0.0007 | 0.0035 | 0.0031 |
| 188 | Masco Corp. | MAS | 4.71 | 12.3 | 4.0 | 8.2 | 7,055.41 | 0.0007 | 0.0035 | 0.0060 |
| 189 | Mattel, Inc | MAT | 3.51 | 9.8 | 9.5 | 9.7 | 7,887.08 | 0.0008 | 0.0029 | 0.0079 |
| 190 | MBIA Inc. | MBI | 10.65 | 12.5 | 6.0 | 9.3 | 1,601.18 | 0.0002 | 0.0018 | 0.0015 |
| 191 | McCormick & Co. | MKC | 2.43 | 9.5 | 7.5 | 8.5 | 4,623.13 | 0.0005 | 0.0012 | 0.0041 |
| 192 | McDonald's Corp. | MCD | 2.76 | 9.4 | 11.0 | 10.2 | 64,362.53 | 0.0067 | 0.0185 | 0.0685 |

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 193 | McGraw-Hill | MHP | 2.35 | 8.9 | 12.5 | 10.7 | 12,301.31 | 0.0013 | 0.0030 | 0.0137 |
| 194 | McKesson Corp | MCK | 0.43 | 14.3 | 12.5 | 13.4 | 15,964.36 | 0.0017 | 0.0007 | 0.0223 |
| 195 | MeadWestvaco | MWV | 3.47 | 11.0 | 18.0 | 14.5 | 4,892.23 | 0.0005 | 0.0018 | 0.0074 |
| 196 | Medtronic, Inc. | MDT | 1.03 | 13.7 | 12.0 | 12.9 | 54,500.50 | 0.0057 | 0.0059 | 0.0731 |
| 197 | Merck & Co | MRK | 3.51 | 9.9 | 8.0 | 9.0 | 94,199.69 | 0.0098 | 0.0345 | 0.0880 |
| 198 | Meredith Corp. | MDP | 2.16 | 11.8 | 10.5 | 11.2 | 1,876.13 | 0.0002 | 0.0004 | 0.0022 |
| 199 | Merrill Lynch & Co. | MER | 2.99 | 12.0 | 5.5 | 8.8 | 40,074.32 | 0.0042 | 0.0125 | 0.0366 |
| 200 | MetLife Inc | MET | 1.23 | 10.7 | 11.5 | 11.1 | 44,565.21 | 0.0046 | 0.0057 | 0.0516 |
| 201 | MGIC Investment | MTG | 0.77 | 9.7 | (7.5) | 1.1 | 1,068.22 | 0.0001 | 0.0001 | 0.0001 |
| 202 | Microchip Technology | MCHP | 3.84 | 13.7 | 12.0 | 12.9 | 6,309.25 | 0.0007 | 0.0025 | 0.0085 |
| 203 | Microsoft Corp | MSFT | 1.51 | 12.8 | 17.5 | 15.2 | 272,220.20 | 0.0284 | 0.0429 | 0.4303 |
| 204 | Molex Inc. | MOLX | 1.96 | 14.4 | 9.0 | 11.7 | 4,144.16 | 0.0004 | 0.0008 | 0.0051 |
| 205 | Monsanto Co. | MON | 0.72 | 36.9 | 25.5 | 31.2 | 53,152.16 | 0.0055 | 0.0040 | 0.1730 |
| 206 | Moody's Corp | MCO | 1.12 | 11.0 | 10.5 | 10.8 | 9,219.11 | 0.0010 | 0.0011 | 0.0103 |
| 207 | Morgan Stanley | MS | 2.17 | 12.6 | 1.5 | 7.1 | 52,771.89 | 0.0055 | 0.0119 | 0.0388 |
| 208 | Motorola, Inc | MOT | 2.16 | 9.6 | 6.0 | 7.8 | 20,933.68 | 0.0022 | 0.0047 | 0.0170 |
| 209 | Murphy Oil Corp | MUR | 1.00 | 19.6 | 11.5 | 15.6 | 14,262.41 | 0.0015 | 0.0015 | 0.0231 |
| 210 | National City Corp. | NCC | 7.64 | 10.4 | 2.5 | 6.5 | 6,973.40 | 0.0007 | 0.0056 | 0.0047 |
| 211 | National Semic | NSM | 1.32 | 10.5 | 13.0 | 11.8 | 4,649.14 | 0.0005 | 0.0006 | 0.0057 |
| 212 | New York Times | NYT | 4.72 | 5.6 | (2.5) | 1.6 | 2,802.49 | 0.0003 | 0.0014 | 0.0005 |
| 213 | Newell Rubbermaid | NWL | 3.65 | 9.5 | 10.0 | 9.8 | 6,361.33 | 0.0007 | 0.0024 | 0.0065 |
| 214 | Newmont Mining | NEM | 0.87 | 18.1 | 1.5 | 9.8 | 20,771.31 | 0.0022 | 0.0019 | 0.0212 |
| 215 | Nicor Inc. | GAS | 5.58 | 4.0 | 4.0 | 4.0 | 1,503.98 | 0.0002 | 0.0009 | 0.0006 |
| 216 | NIKE, Inc. 'B' | NKE | 1.37 | 13.4 | 13.0 | 13.2 | 33,446.64 | 0.0035 | 0.0048 | 0.0461 |
| 217 | NiSource Inc | NI | 5.26 | 2.9 | 5.0 | 4.0 | 4,795.34 | 0.0005 | 0.0026 | 0.0020 |
| 218 | Noble Corp. | NE | 0.34 | 20.2 | 28.5 | 24.4 | 12,510.52 | 0.0013 | 0.0004 | 0.0318 |
| 219 | Noble Energy | NBL | 0.68 | 10.1 | 2.5 | 6.3 | 12,191.52 | 0.0013 | 0.0009 | 0.0080 |
| 220 | Nordstrom, Inc | JWN | 1.82 | 11.5 | 14.0 | 12.8 | 8,172.24 | 0.0009 | 0.0016 | 0.0109 |
| 221 | Norfolk Southern | NSC | 2.19 | 15.1 | 12.0 | 13.6 | 20,550.83 | 0.0021 | 0.0047 | 0.0291 |
| 222 | Northern Trust Corp. | NTRS | 1.61 | 11.8 | 9.0 | 10.4 | 15,354.32 | 0.0016 | 0.0026 | 0.0167 |
| 223 | Northrop Grumman | NOC | 1.89 | 15.6 | 11.5 | 13.6 | 26,496.32 | 0.0028 | 0.0052 | 0.0375 |
| 224 | Nucor Corp. | NUE | 1.86 | 8.0 | 8.5 | 8.3 | 19,855.38 | 0.0021 | 0.0039 | 0.0171 |
| 225 | Occidental Petroleum | OXY | 1.43 | 11.6 | 4.0 | 7.8 | 57,952.01 | 0.0060 | 0.0086 | 0.0472 |
| 226 | OfficeMax | OMX | 3.08 | 10.4 | 24.0 | 17.2 | 1,470.24 | 0.0002 | 0.0005 | 0.0026 |
| 227 | Omnicom Group | OMC | 1.39 | 11.7 | 10.5 | 11.1 | 14,141.70 | 0.0015 | 0.0021 | 0.0164 |
| 228 | PACCAR Inc. | PCAR | 1.53 | 11.7 | 13.5 | 12.6 | 17,230.01 | 0.0018 | 0.0028 | 0.0226 |
| 229 | Pall Corp. | PLL | 1.40 | 15.5 | 13.5 | 14.5 | 4,543.45 | 0.0005 | 0.0007 | 0.0069 |
| 230 | Parker-Hannifin | PH | 1.29 | 21.0 | 13.0 | 17.0 | 10,974.34 | 0.0011 | 0.0015 | 0.0195 |
| 231 | Paychex, Inc. | PAYX | 3.64 | 14.7 | 14.5 | 14.6 | 11,997.54 | 0.0013 | 0.0046 | 0.0183 |
| 232 | Peabody Energy | BTU | 0.51 | 15.2 | 16.5 | 15.9 | 12,598.21 | 0.0013 | 0.0007 | 0.0208 |
| 233 | Penney (J.C.) | JCP | 1.90 | 13.8 | 10.0 | 11.9 | 9,350.64 | 0.0010 | 0.0019 | 0.0116 |
| 234 | Pepco Holdings | POM | 4.39 | 11.4 | 11.0 | 11.2 | 4,766.69 | 0.0005 | 0.0022 | 0.0056 |
| 235 | Pepsi Bottling Group | PBG | 1.63 | 9.5 | 9.0 | 9.3 | 7,685.44 | 0.0008 | 0.0013 | 0.0074 |
| 236 | PepsiCo, Inc | PEP | 2.11 | 10.9 | 10.5 | 10.7 | 114,615.90 | 0.0120 | 0.0252 | 0.1279 |
| 237 | PerkinElmer Inc | PKI | 1.20 | 14.8 | 15.0 | 14.9 | 2,758.91 | 0.0003 | 0.0003 | 0.0043 |
| 238 | Pfizer, Inc. | PFE | 6.22 | 4.4 | 2.0 | 3.2 | 139,209.00 | 0.0145 | 0.0903 | 0.0465 |
| 239 | PG&E Corp. | PCG | 4.22 | 8.1 | 4.5 | 6.3 | 13,038.73 | 0.0014 | 0.0057 | 0.0086 |
| 240 | Pinnacle West Capital | PNW | 5.86 | 3.6 | 1.5 | 2.6 | 3,598.37 | 0.0004 | 0.0022 | 0.0010 |
| 241 | Pitney Bowes | PBI | 3.97 | 10.7 | 5.5 | 8.1 | 7,665.83 | 0.0008 | 0.0032 | 0.0065 |
| 242 | Plum Creek Timber | PCL | 4.09 | 6.5 | 2.5 | 4.5 | 7,039.28 | 0.0007 | 0.0030 | 0.0033 |
| 243 | PNC Financial Serv. | PNC | 3.73 | 9.7 | 8.0 | 8.9 | 22,750.87 | 0.0024 | 0.0089 | 0.0210 |
| 244 | Polo Ralph Lauren 'A' | RL | 0.33 | 15.2 | 15.0 | 15.1 | 6,137.52 | 0.0006 | 0.0002 | 0.0097 |
| 245 | PPG Inds | PPG | 3.52 | 12.1 | 7.5 | 9.8 | 9,670.75 | 0.0010 | 0.0036 | 0.0099 |
| 246 | PPL Corp. | PPL | 2.91 | 12.4 | 14.0 | 13.2 | 17,268.75 | 0.0018 | 0.0052 | 0.0238 |
| 247 | Praxair Inc. | PX | 1.84 | 13.4 | 13.0 | 13.2 | 25,816.25 | 0.0027 | 0.0050 | 0.0356 |
| 248 | Precision Castparts | PCP | 0.12 | 18.6 | 20.5 | 19.6 | 13,492.61 | 0.0014 | 0.0002 | 0.0275 |
| 249 | Price (T. Rowe) Group | TROW | 1.90 | 14.3 | 17.5 | 15.9 | 13,361.71 | 0.0014 | 0.0026 | 0.0222 |
| 250 | Principal Fin'l Group | PFG | 1.62 | 11.2 | 10.5 | 10.9 | 14,560.88 | 0.0015 | 0.0025 | 0.0165 |
| 251 | Procter & Gamble | PG | 2.02 | 13.3 | 11.5 | 12.4 | 213,486.00 | 0.0223 | 0.0450 | 0.2762 |
| 252 | Progress Energy | PGN | 5.88 | 5.9 | 3.5 | 4.7 | 10,831.38 | 0.0011 | 0.0066 | 0.0053 |
| 253 | Progressive (Ohio) | PGR | 0.89 | 6.9 | 4.0 | 5.5 | 11,060.05 | 0.0012 | 0.0010 | 0.0063 |
| 254 | Prudential Fin'l | PRU | 1.51 | 14.2 | 13.5 | 13.9 | 34,047.14 | 0.0036 | 0.0054 | 0.0492 |
| 255 | Public Serv. Enterprise | PEG | 3.13 | 15.6 | 10.5 | 13.1 | 20,940.17 | 0.0022 | 0.0068 | 0.0285 |
| 256 | Pulte Homes | PHM | 1.09 | 14.0 | (9.0) | 2.5 | 3,771.63 | 0.0004 | 0.0004 | 0.0010 |

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 257 | Qualcomm Inc. | QCOM | 1.46 | 18.9 | 11.5 | 15.2 | 62,341.82 | 0.0065 | 0.0095 | 0.0989 |
| 258 | Quest Diagnostics | DGX | 0.89 | 13.9 | 9.5 | 11.7 | 8,725.98 | 0.0009 | 0.0008 | 0.0107 |
| 259 | Questar Corp. | STR | 0.91 | 9.0 | 9.0 | 9.0 | 9,323.05 | 0.0010 | 0.0009 | 0.0088 |
| 260 | RadioShack Corp. | RSH | 1.51 | 9.2 | 4.0 | 6.6 | 2,169.49 | 0.0002 | 0.0003 | 0.0015 |
| 261 | Range Resources Corp | RRC | 0.27 | 15.0 | 20.5 | 17.8 | 8,804.91 | 0.0009 | 0.0002 | 0.0163 |
| 262 | Raytheon Co. | RTN | 1.60 | 15.7 | 13.0 | 14.4 | 27,157.21 | 0.0028 | 0.0045 | 0.0407 |
| 263 | Regions Financial | RF | 7.00 | 7.5 | 5.5 | 6.5 | 15,146.03 | 0.0016 | 0.0111 | 0.0103 |
| 264 | Reynolds American | RAI | 5.61 | 6.0 | 7.5 | 6.8 | 17,882.84 | 0.0019 | 0.0105 | 0.0126 |
| 265 | Rockwell Automation | ROK | 2.13 | 14.0 | 13.5 | 13.8 | 8,077.41 | 0.0008 | 0.0018 | 0.0116 |
| 266 | Rockwell Collins | COL | 1.17 | 17.1 | 11.5 | 14.3 | 8,936.83 | 0.0009 | 0.0011 | 0.0133 |
| 267 | Rohm and Haas | ROH | 2.81 | 12.8 | 10.0 | 11.4 | 10,315.91 | 0.0011 | 0.0030 | 0.0123 |
| 268 | Rowan Cos | RDC | 1.10 | 15.0 | 18.5 | 16.8 | 4,064.89 | 0.0004 | 0.0005 | 0.0071 |
| 269 | Ryder System | R | 1.48 | 12.7 | 9.5 | 11.1 | 3,613.34 | 0.0004 | 0.0006 | 0.0042 |
| 270 | Safeco Corp. | SAF | 3.63 | 9.5 | 4.5 | 7.0 | 4,241.12 | 0.0004 | 0.0016 | 0.0031 |
| 271 | Safeway Inc | SWY | 0.95 | 10.7 | 12.0 | 11.4 | 12,814.96 | 0.0013 | 0.0013 | 0.0152 |
| 272 | Sara Lee Corp | SLE | 3.16 | 7.5 | 4.5 | 6.0 | 9,479.04 | 0.0010 | 0.0031 | 0.0059 |
| 273 | Schering-Plough | SGP | 1.26 | 18.4 | 35.5 | 27.0 | 33,302.83 | 0.0035 | 0.0044 | 0.0936 |
| 274 | Schlumberger Ltd | SLB | 1.04 | 19.8 | 17.5 | 18.7 | 96,434.71 | 0.0101 | 0.0105 | 0.1876 |
| 275 | Schwab (Charles) | SCHW | 1.03 | 18.8 | 20.0 | 19.4 | 22,476.88 | 0.0023 | 0.0024 | 0.0455 |
| 276 | Scripps (E W.) 'A' | SSP | 1.33 | 8.6 | 8.5 | 8.6 | 6,856.49 | 0.0007 | 0.0010 | 0.0061 |
| 277 | Sealed Air | SEE | 1.97 | 10.3 | 13.0 | 11.7 | 3,928.67 | 0.0004 | 0.0008 | 0.0048 |
| 278 | Sempra Energy | SRE | 2.59 | 7.5 | 4.5 | 6.0 | 12,924.72 | 0.0013 | 0.0035 | 0.0081 |
| 279 | Sherwin-Williams | SHW | 2.60 | 14.1 | 11.0 | 12.6 | 6,760.55 | 0.0007 | 0.0018 | 0.0089 |
| 280 | Sigma-Aldrich | SIAL | 0.91 | 9.9 | 10.0 | 10.0 | 7,441.20 | 0.0008 | 0.0007 | 0.0077 |
| 281 | Smith Int'l Inc | SII | 0.81 | 21.8 | 20.5 | 21.2 | 11,939.88 | 0.0012 | 0.0010 | 0.0263 |
| 282 | Snap-on Inc. | SNA | 2.44 | 10.7 | 19.5 | 15.1 | 2,836.95 | 0.0003 | 0.0007 | 0.0045 |
| 283 | Southern Co. | SO | 4.46 | 5.3 | 5.5 | 5.4 | 27,439.94 | 0.0029 | 0.0128 | 0.0155 |
| 284 | Southwest Airlines | LUV | 0.15 | 11.8 | 15.0 | 13.4 | 9,008.61 | 0.0009 | 0.0001 | 0.0126 |
| 285 | Sprint Nextel Corp | S | 1.57 | 8.0 | 27.0 | 17.5 | 18,122.65 | 0.0019 | 0.0030 | 0.0331 |
| 286 | Stanley Works | SWK | 2.57 | 11.4 | 9.5 | 10.5 | 3,965.19 | 0.0004 | 0.0011 | 0.0043 |
| 287 | Staples, Inc. | SPLS | 1.44 | 13.7 | 14.0 | 13.9 | 16,031.43 | 0.0017 | 0.0024 | 0.0232 |
| 288 | Starwood Hotels | HOT | 1.73 | 13.8 | 13.5 | 13.7 | 10,449.48 | 0.0011 | 0.0019 | 0.0149 |
| 289 | State Street Corp. | STT | 1.10 | 12.2 | 14.5 | 13.4 | 32,114.91 | 0.0034 | 0.0037 | 0.0447 |
| 290 | Stryker Corp | SYK | 0.51 | 17.9 | 17.5 | 17.7 | 26,345.37 | 0.0027 | 0.0014 | 0.0486 |
| 291 | Sunoco, Inc | SUN | 2.16 | 13.6 | 3.5 | 8.6 | 6,546.97 | 0.0007 | 0.0015 | 0.0058 |
| 292 | SunTrust Banks | STI | 4.95 | 10.6 | 3.0 | 6.8 | 21,664.06 | 0.0023 | 0.0112 | 0.0154 |
| 293 | SUPERVALU INC. | SVU | 2.39 | 7.8 | 10.5 | 9.2 | 6,044.12 | 0.0006 | 0.0015 | 0.0058 |
| 294 | Sysco Corp. | SYY | 3.00 | 13.1 | 13.0 | 13.1 | 17,758.16 | 0.0019 | 0.0056 | 0.0242 |
| 295 | Target Corp. | TGT | 1.07 | 14.8 | 12.0 | 13.4 | 44,235.75 | 0.0046 | 0.0049 | 0.0618 |
| 296 | TECO Energy | TE | 5.11 | 4.7 | 4.0 | 4.4 | 3,217.97 | 0.0003 | 0.0017 | 0.0015 |
| 297 | Tesoro Corp. | TSO | 1.34 | 12.7 | 6.0 | 9.4 | 4,100.36 | 0.0004 | 0.0006 | 0.0040 |
| 298 | Texas Instruments | TXN | 1.41 | 16.4 | 10.5 | 13.5 | 39,541.27 | 0.0041 | 0.0058 | 0.0555 |
| 299 | Textron. Inc | TXT | 1.72 | 13.0 | 15.0 | 14.0 | 13,341.58 | 0.0014 | 0.0024 | 0.0195 |
| 300 | Tiffany & Co. | TIF | 1.55 | 13.0 | 15.5 | 14.3 | 5,235.78 | 0.0005 | 0.0008 | 0.0078 |
| 301 | Time Warner | TWX | 1.76 | 13.2 | 8.5 | 10.9 | 51,416.68 | 0.0054 | 0.0094 | 0.0582 |
| 302 | TJX Companies | TJX | 1.06 | 12.6 | 14.0 | 13.3 | 14,827.99 | 0.0015 | 0.0016 | 0.0206 |
| 303 | Torchmark Corp | TMK | 0.92 | 8.2 | 8.5 | 8.4 | 5,615.24 | 0.0006 | 0.0005 | 0.0049 |
| 304 | Total System Svcs. | TSS | 1.23 | 12.9 | 9.0 | 11.0 | 4,498.91 | 0.0005 | 0.0006 | 0.0051 |
| 305 | Travelers Cos. | TRV | 2.43 | 9.4 | 10.0 | 9.7 | 30,877.12 | 0.0032 | 0.0078 | 0.0312 |
| 306 | Tyson Foods 'A' | TSN | 0.95 | 8.7 | 26.5 | 17.6 | 6,012.84 | 0.0006 | 0.0006 | 0.0110 |
| 307 | U.S. Bancorp | USB | 4.93 | 8.1 | 5.0 | 6.6 | 59,645.58 | 0.0062 | 0.0307 | 0.0408 |
| 308 | U.S. Steel Corp. | X | 0.87 | 9.7 | 5.0 | 7.4 | 13,534.39 | 0.0014 | 0.0012 | 0.0104 |
| 309 | Union Pacific | UNP | 1.44 | 14.8 | 16.5 | 15.7 | 32,032.21 | 0.0033 | 0.0048 | 0.0523 |
| 310 | United Parcel Serv | UPS | 2.51 | 13.2 | 8.0 | 10.6 | 74,956.37 | 0.0078 | 0.0196 | 0.0829 |
| 311 | United Technologies | UTX | 1.86 | 12.2 | 13.5 | 12.9 | 68,216.93 | 0.0071 | 0.0132 | 0.0915 |
| 312 | UnitedHealth Group | UNH | 0.09 | 14.8 | 14.0 | 14.4 | 45,421.52 | 0.0047 | 0.0004 | 0.0682 |
| 313 | Unum Group | UNM | 1.38 | 10.2 | 11.0 | 10.6 | 7,855.27 | 0.0008 | 0.0011 | 0.0087 |
| 314 | UST Inc. | UST | 4.54 | 7.0 | 5.0 | 6.0 | 8,707.79 | 0.0009 | 0.0041 | 0.0055 |
| 315 | V.F. Corp | VFC | 2.94 | 10.0 | 12.5 | 11.3 | 8,660.37 | 0.0009 | 0.0027 | 0.0102 |
| 316 | Valero Energy | VLO | 0.97 | 16.9 | 5.5 | 11.2 | 26,569.99 | 0.0028 | 0.0027 | 0.0310 |
| 317 | Verizon Communic. | VZ | 4.76 | 8.4 | 4.5 | 6.5 | 104,398.60 | 0.0109 | 0.0518 | 0.0703 |
| 318 | Vulcan Materials | VMC | 2.98 | 9.0 | 13.0 | 11.0 | 7,136.36 | 0.0007 | 0.0022 | 0.0082 |
| 319 | Wachovia Corp | WB | 8.33 | 9.6 | 5.0 | 7.3 | 58,398.72 | 0.0061 | 0.0508 | 0.0445 |
| 320 | Walgreen Co. | WAG | 1.03 | 13.6 | 10.0 | 11.8 | 36,462.95 | 0.0038 | 0.0039 | 0.0449 |

| | Company | Ticker | Dividend Yield | IBES Growth Rate | Value Line EPS Growth Rate | Average EPS Growth | Market Cap $ (Mil) | Market Weight | Weighted Dividend Yield | Weighted Average Growth Rate |
|---|---|---|---|---|---|---|---|---|---|---|
| 321 | Wal-Mart Stores | WMT | 1 79 | 11.7 | 10.0 | 10.9 | 213,176.00 | 0.0222 | 0 0398 | 0.2413 |
| 322 | Washington Mutual | WM | 5 13 | 8.7 | 2.0 | 5 4 | 10,167.72 | 0 0011 | 0.0054 | 0.0057 |
| 323 | Washington Post | WPO | 1.30 | 10.0 | 4.5 | 7.3 | 6,307 71 | 0.0007 | 0.0009 | 0.0048 |
| 324 | Waste Management | WMI | 3 24 | 11.0 | 10.5 | 10 8 | 16,663.93 | 0.0017 | 0.0056 | 0.0187 |
| 325 | Wells Fargo | WFC | 3.81 | 9.7 | 7 5 | 8 6 | 108,236.10 | 0.0113 | 0.0430 | 0.0971 |
| 326 | Wendy's Int'l | WEN | 2.09 | 12 1 | 9 0 | 10.6 | 2,088 29 | 0.0002 | 0.0005 | 0.0023 |
| 327 | Weyerhaeuser Co | WY | 3 79 | 5.7 | 9.5 | 7.6 | 13,274.74 | 0.0014 | 0 0052 | 0.0105 |
| 328 | Whirlpool Corp. | WHR | 1 94 | 12.5 | 12.0 | 12 3 | 6,833.75 | 0.0007 | 0.0014 | 0.0087 |
| 329 | Whole Foods Market | WFMI | 2.45 | 19 2 | 22.0 | 20.6 | 4,555.03 | 0.0005 | 0.0012 | 0.0098 |
| 330 | Williams Cos | WMB | 1.26 | 19 7 | 23.5 | 21 6 | 18,800.86 | 0.0020 | 0.0025 | 0.0424 |
| 331 | Wrigley (Wm.) Jr. | WWY | 2.16 | 10.5 | 9 5 | 10 0 | 17,021.63 | 0.0018 | 0.0038 | 0.0178 |
| 332 | Wyeth | WYE | 2.69 | 4.6 | 9.0 | 6.8 | 55,775.14 | 0.0058 | 0.0157 | 0.0396 |
| 333 | Xcel Energy Inc | XEL | 4.57 | 6 5 | 5.5 | 6.0 | 8,461.49 | 0.0009 | 0.0040 | 0.0053 |
| 334 | Xerox Corp | XRX | 1 11 | 12.3 | 13.0 | 12 7 | 14,106.74 | 0.0015 | 0.0016 | 0.0186 |
| 335 | Xilinx Inc. | XLNX | 2.34 | 14 2 | 13 5 | 13.9 | 6,863.08 | 0.0007 | 0.0017 | 0.0099 |
| 336 | XTO Energy | XTO | 0.84 | 9 3 | 9.0 | 9 2 | 27,804.07 | 0.0029 | 0.0024 | 0.0265 |
| 337 | Yum! Brands | YUM | 1 60 | 11.9 | 12.0 | 12 0 | 19,148.80 | 0.0020 | 0.0032 | 0.0239 |
| 338 | Zions Bancorp | ZION | 3.41 | 9.0 | 4.0 | 6.5 | 5,402.31 | 0.0006 | 0.0019 | 0.0037 |
| | | | | | | | 9,585,307 1 | 1 0000 | 2.4 | 10.9 |

Sources:
www.standardandpoors.com (retrieved Mar 27, 2008).
www valueline.com (retrieved Mar. 27, 2008)
Thomson Financial, *Company in Context Report* (retrieved Mar. 27, 2008).

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 22**

**Responding Witness: Valerie L. Scott**

Q-22. Refer to Volume 4 of 5 of LG&E's application, the Testimony of Valerie L. Scott ("Scott Testimony"), at pages 3 and 11 and to Reference Schedule 1.15 of Exhibit 1 to the Rives Testimony at page 4 of 4. Provide the calculations showing the derivation of the $218,397 amount identified as the "Company Match increase from 60% to 70%."

A-22. See attached.

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**
**Derivation of 401(k) Company Match Increase Effective November 12, 2007**

| | | | |
|---|---|---|---|
| 1. | 401(k) O&M Expense for May - October 2007 | | |
| 2. | LG&E | $ 824,971 | |
| 3. | Servco allocated to LG&E | 485,412 | |
| 4. | Total 401(k) O&M expense before increase | $ 1,310,383 | (Line 2 + Line 3) |
| 5. | Gross Up Company Match Factor | 60% | |
| 6. | Total 401(k) Contribution | $ 2,183,972 | (Line 4/ Line 5) |
| 7. | Ongoing Company Match Factor | 70% | |
| 8. | Ongoing Company Match for May 2007 - October 2007 | $ 1,528,780 | (Line 6 x Line 7) |
| 9. | Total LG&E Increase from 60% to 70% | $ 218,397 | (Line 8 - Line 4) |

e·on | U.S.

November 9, 2007

**E.ON U.S. LLC**
220 West Main Street
P.O. Box 32030
Louisville, Kentucky 40232

Internal Communications
T 502-627-2520
F 502-627-3629
internal.communications
@eon-us.com

**Enhancements to Company Savings Plan Announced**
*Company Match to Increase to 70 Percent; New Investment Options Offered*

Dear Employees:

Saving for retirement is a critical part of your financial well being, and E.ON U.S. is committed to seeking opportunities to help enrich your long-term savings. This commitment has led us to some exciting key enhancements to the company-sponsored savings plan, making this benefit even more powerful in creating a solid financial future for you and your loved ones.

These enhancements — which impact both the E.ON U.S. LLC and Louisville Gas & Electric Bargaining Employees' Savings Plans — include an increased company match, an expanded selection of funds and lower fees on select funds.

**Increased Company Match**

Effective Nov. 12, the company will increase its matching contribution from 60 percent to 70 percent per dollar for employee contributions up to 6 percent of your eligible compensation per pay period (subject to IRS maximum limits). Therefore, a minimum contribution of 6 percent will receive the maximum benefit provided by this increase.

**Vanguard Funds**

Additionally, effective Nov. 15, the plan will offer five new Vanguard Target Retirement Funds and will lower the fees on three existing funds.

The five new Vanguard funds — which are classified by retirement years ranging from 2010 to 2050 — make it easier for employees to select the proper fund based on the date they plan to retire. Each fund offers a diversified mix of investments and, over time, assumes a more conservative risk strategy as you move closer to retirement.

The funds that will change their share class status are: Lord Abbett Small-Cap Value Fund (Class A); PIMCO Total Return Fund (Administrative Class); and American Funds The Growth Fund of America (Class R4). Investors in the three funds should note a brief blackout period beginning Nov. 13 at 3:30 p.m. and ending Nov. 15 at 9 a.m. (Eastern time). A blackout period allows for standard administrative processing to complete the fund transfers. During this time, fund participants will be unable to perform transactions for the three funds; however, you will have complete access to all your other investment choices.

Watch for more information on these funds in an upcoming *News Transmission* article.

To change your current savings plan deferral or begin contributing to the plan, contact our savings plan administrator, Mercer. You may reach Mercer at www.yourbenefits.mercerhrs.com or call 1-866-321-0968 between 8 a.m. and 10 p.m., Monday through Friday (Eastern time).

The company is pleased to offer these enhancements to your savings plan, a wonderful resource to help you plan a secure and comfortable future.

Sincerely,

Paula Pottinger

**Paula H. Pottinger**
*Senior Vice President, Human Resources*

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 23**

**Responding Witness: Valerie L. Scott**

Q-23. Refer to pages 3-4 and 11 of the Scott Testimony and Reference Schedule 1.16 of Exhibit 1 to the Rives Testimony. Provide the calculations, workpapers, etc., which show the derivation of the pension and post-retirement expenses annualized shown on Line 2 of the reference schedule.

A-23. See attached for calculation of the derivation of the pension and post-retirement expenses annualized at 23(1) and the Mercer study on 2008 Pension (SFAS No. 87) Expense for Retirement Plans at 23(4). An error was identified in the calculation of the ratio of expense to total pension and post retirement costs. We have also provided the requested schedules using the correct expense/capital ratio (see 23(2)) and a revised Exhibit 1, Reference Schedule 1.16 (see 23(3)). The corrected Reference Schedule 1.16 reflects a decrease in expense for the pro forma adjustment of $447,670 for electric operations and $119,002 for gas operations.

For the Mercer study on post-retirement benefits (SFAS No. 106), see attachment to PSC-1 Question No. 54, page 4 of 5 in this case.

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Pension Expense Annualization**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1. | Company O&M Pension expense (excluding Servco) | | $ 2,666,584 | |
| 2. | Total Company Pension costs (excluding Servco) | | 3,201,638 | |
| 3. | % O&M to total | (Line 1/Line 2) | 83.28813% | |
| 4. | Servco O&M Pension expense charged to LG&E | | | $ 4,626,890 |
| 5. | Total Servco Pension costs charged to LG&E | | | 5,914,030 |
| 6. | % O&M to total | (Line 4/Line 5) | | 78.23582% |
| 7. | Projected 2008 Cost per Mercer Study<br>(for LG&E includes LG&E Union and Non-Union Plans) | | $ 4,939,436 | $ 12,374,615 |
| 8. | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 9 | Expected O&M expenses | (Line 3, Line 6 x Line 7) | $ 4,113,964 | $ 9,681,382 |
| 10 | Servco O&M charged to LG&E | (Line 8 x Line 9 Servco) | 4,075,862 | |
| 11 | Total O&M costs for 2008 Mercer target | (Line 9 + Line 10) | $ 8,189,826 | |

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Post Retirement (SFAS 106) Expense Annualization**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1 | Company O&M SFAS No 106 expense (excluding Servco) | | $ 6,194,978 | |
| 2 | Total Company SFAS No. 106 costs (excluding Servco) | | 7,781,134 | |
| 3 | % O&M to total | (Line 1/Line 2) | 79.61536% | |
| 4 | Servco O&M SFAS No 106 expense charged to LG&E | | | $ 624,940 |
| 5 | Total Servco SFAS No. 106 costs charged to LG&E | | | 799,116 |
| 6 | % O&M to total | (Line 4/Line 5) | | 78 20392% |
| 7 | Projected 2008 Cost per Mercer Study (for LG&E includes LG&E Union and Non-Union Plans) | | $ 8,403,153 | $ 2,020,105 |
| 8 | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 9 | Expected O&M expenses | (Line 3, Line 6 x Line 7) | $ 6,690,201 | $ 1,579,801 |
| 10 | Servco O&M charged to LG&E | (Line 8 x Line 9 Servco) | 665,096 | |
| 11 | Total O&M costs for 2008 Mercer target | (Line 9 + Line 10) | $ 7,355,297 | |

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Pension Expense Annualization - Corrected for Change in Capitalization Rate**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1. | Company O&M Pension expense (excluding Servco) | | $ 2,666,584 | |
| 2 | Total Company Pension costs (excluding Servco) | | 3,426,602 | |
| 3. | % O&M to total | (Line 1/Line 2) | 77.82008% | |
| 4. | Servco O&M Pension expense charged to LG&E | | | $ 4,626,890 |
| 5. | Total Servco Pension costs charged to LG&E | | | 5,914,030 |
| 6. | % O&M to total | (Line 4/Line 5) | | 78.23582% |
| 7 | Projected 2008 Cost per Mercer Study<br>(for LG&E includes LG&E Union and Non-Union Plans) | | $ 4,939,436 | $ 12,374,615 |
| 8 | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 9. | Expected O&M expenses | (Line 3, Line 6 x Line 7) | $ 3,843,873 | $ 9,681,382 |
| 10 | Servco O&M charged to LG&E | (Line 8 x Line 9 Servco) | 4,075,862 | |
| 11 | Total O&M costs for 2008 Mercer target | (Line 9 + Line 10) | $ 7,919,735 | |

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Post Retirement (SFAS 106) Expense Annualization - Corrected for Change in Capitalization Rate**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1 | Company O&M SFAS No 106 expense (excluding Servco) | | $ 6,194,978 | |
| 2 | Total Company SFAS No. 106 costs (excluding Servco) | | 8,142,077 | |
| 3 | % O&M to total | (Line 1/Line 2) | 76.08597% | |
| 4 | Servco O&M SFAS No 106 expense charged to LG&E | | | $ 624,940 |
| 5 | Total Servco SFAS No. 106 costs charged to LG&E | | | 799,116 |
| 6 | % O&M to total | (Line 4/Line 5) | | 78.20392% |
| 7 | Projected 2008 Cost per Mercer Study (for LG&E includes LG&E Union and Non-Union Plans) | | $ 8,403,153 | $ 2,020,105 |
| 8 | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 9 | Expected O&M expenses | (Line 3, Line 6 x Line 7) | $ 6,393,620 | $ 1,579,801 |
| 10 | Servco O&M charged to LG&E | (Line 8 x Line 9 Servco) | 665,096 | |
| 11 | Total O&M costs for 2008 Mercer target | (Line 9 + Line 10) | $ 7,058,716 | |

Exhibit 1
Reference Schedule 1.16
Sponsoring Witness: Scott

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**Revised**
**To Adjust for Pension and Post Retirement**
**For the Twelve Months Ended April 30, 2008**

| | | | Pension | Post Retirement | Total | Proforma per Filing | Difference |
|---|---|---|---|---|---|---|---|
| 1 | Pension and Post Retirement expenses in test year | | $ 7,293,474 | $ 6,819,918 | $ 14,113,392 | | |
| 2 | Pension and Post Retirement expenses annualized for 2008 Mercer Study | | 7,919,735 | 7,058,716 | 14,978,451 | | |
| 3 | Total adjustment (Line 2 - Line 1) | | $ 626,261 | $ 238,798 | $ 865,059 | $ 1,431,731 | $ (566,672) |
| 4 | Electric Department (a) | 79% | | | $ 683,397 | $ 1,131,067 | $ (447,670) |
| 5 | Gas Department (a) | 21% | | | 181,662 | 300,664 | (119,002) |
| 6 | Total Adjustment | | | | $ 865,059 | $ 1,431,731 | $ (566,672) |

(a) Percentages taken from Reference Schedule 1.15

**Linda C. Myers, F.S.A.**
Principal

462 South Fourth Street. Suite 1100
Louisville, KY 40202
502 561 4726 Fax 502 561 4748
linda.myers@mercer.com
www.mercer.com

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

February 29, 2008

Ms. Becky Smith
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40202

**Private & Confidential**

**Subject: 2008 FAS 87 and IFRS Expense for Retirement Plans**

Dear Becky:

Enclosed are exhibits illustrating the 2008 FAS 87 expense (both for financial and regulatory accounting purposes) and the 2008 IFRS expense by component for the Qualified and Non-Qualified Retirement Plans of E.ON U.S. LLC. Due to the increase in discount rates, the expense amounts are less than the 2008 budgeted amounts provided last year. We have included a reconciliation of the actual 2008 FAS 87 and IFRS expenses to the 2008 budget estimates provided on April 13, 2007.

A measurement date of December 31, 2007 was used in these calculations. Plan liabilities were based on census data collected as of September 30, 2007. The market values of assets as of December 31, 2007 were provided by you. All other methods, assumptions and plan provisions used in calculating the 2008 FAS 87 and IFRS expenses were the same as those used in the applicable December 31, 2007 disclosures. The 2008 expense amounts do not anticipate any contributions to the qualified plans during the 2008 calendar year.

The undersigned credentialed actuary meets the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this report.

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN



If you have any questions, please give me a call.

Sincerely,

Linda

Linda C. Myers, F.S.A.
Principal

Copy:
Dan Arbough, Chris Garrett, Elliott Horne, Heather Metts, Ron Miller, Vaneeca Mottley, Ken Mudd, Susan Neal, Brad Rives, Valerie Scott, Cathy Shultz, Vicki Strange, Henry Erk, Marcie Gunnell, Patrick Baker, Jeff Thornton

Enclosures

**The information contained in this document (including any attachments) is not intended by Mercer to be used, and it cannot be used, for the purpose of avoiding penalties under the Internal Revenue Code that may be imposed on the taxpayer.**

# Comparison of Actual 2008 FAS 87 Expense to 2008 Estimated FAS 87 Expense Provided on April 13, 2007 for Retirement Plans of E.ON U.S. LLC

| | (In Millions) | |
|---|---|---|
| | Financial Accounting Purposes (Includes Purchase Accounting) | Regulatory Accounting Purposes (Excludes Purchase Accounting) |
| 2008 Estimated FAS 87 expense provided on April 13, 2007 | $24.4 | $33.5 |
| Decrease due to increase in discount rates | (5.5) | (8.2) |
| Increase due to reflection of 3 additional years of LG&E Union multiplier increases | 1.3 | 1.3 |
| Increase due to liability losses | 0.2 | 0.5 |
| Increase due to assets earning less than assumed | 1.2 | 1.4 |
| Actual 2008 FAS 87 expense | $21.6 | $28.5 |

# Comparison of Actual 2008 IFRS Expense to 2008 Estimated Expense Provided on April 13, 2007 for Retirement Plans of E.ON U.S. LLC

## (In Millions)

| | |
|---|---|
| 2008 Estimated IFRS expense provided on April 13, 2007 | $20.2 |
| Decrease due to increase in discount rates | (3.1) |
| Increase due to liability losses | 0.2 |
| Increase due to assets earning less than assumed | 0.9 |
| Actual 2008 IFRS expense | $18.2 |

**2008 Net Periodic Pension Cost for Qualified Plans**

**Regulatory Accounting Purposes**

| | | NonUnion Retirement Plan | | | |
|---|---|---|---|---|---|
| | LG&E Union | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | $ 1,884,766 | $ 2,201,011 | $ 8,911,696 | $ 5,465,928 | |
| 2. Interest cost | 14,903,019 | 11,181,199 | 12,473,629 | 18,275,304 | |
| 3. Expected return on assets | (19,974,817) | (12,467,974) | (11,657,064) | (20,890,311) | |
| 4. Amortizations: | | | | | |
| a. Transition | 0 | 0 | 0 | 0 | |
| b. Prior service cost | 2,517,335 | 3,218,112 | 2,530,129 | 861,310 | |
| c. Gain/loss | 1,476,785 | 0 | 116,225 | 316,518 | |
| **5. Net periodic pension cost** | **$ 807,088** | **$ 4,132,348** | **$ 12,374,615** | **$ 4,028,749** | |

**Financial Accounting Purposes**

| | | NonUnion Retirement Plan | | | |
|---|---|---|---|---|---|
| | LG&E Union | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | $ 1,884,766 | $ 2,201,011 | $ 8,911,696 | $ 5,465,928 | |
| 2. Interest cost | 14,903,019 | 11,181,199 | 12,473,629 | 18,275,304 | |
| 3. Expected return on assets | (19,974,817) | (12,467,974) | (11,657,064) | (20,890,311) | |
| 4. Amortizations: | | | | | |
| a. Transition | 0 | 0 | 0 | 0 | |
| b. Prior service cost | 1,339,645 | 1,154,544 | 2,282,697 | 23,752 | |
| c. Gain/loss | 0 | 0 | 0 | 0 | |
| **5. Net periodic pension cost** | **$ (1,847,387)** | **$ 2,068,780** | **$ 12,010,958** | **$ 2,874,673** | |

**2008 Net Periodic Pension Cost for Non-Qualified Plans**

**Regulatory Accounting Purposes**

| | | Officer SERP | | | Restoration Plan | | | |
|---|---|---|---|---|---|---|---|---|
| | [redacted] | LG&E | ServCo | [redacted] | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | [redacted] | $ 0 | $ 208,090 | [redacted] | $ 6,691 | $ 208,975 | $ 966 | [redacted] |
| 2. Interest cost | [redacted] | 164,423 | 2,204,880 | [redacted] | 24,951 | 244,617 | 2,317 | [redacted] |
| 3. Expected return on assets | [redacted] | 0 | 0 | [redacted] | 0 | 0 | 0 | [redacted] |
| 4. Amortizations: | | | | | | | | |
| a. Transition | [redacted] | 0 | 0 | [redacted] | 0 | 0 | 0 | [redacted] |
| b. Prior service cost | [redacted] | 15,184 | 109,655 | [redacted] | 12,971 | 115,083 | (162) | [redacted] |
| c. Gain/loss | [redacted] | 61,350 | 467,354 | [redacted] | 0 | 39,661 | 463 | [redacted] |
| **5. Net periodic pension cost** | [redacted] | **$ 240,957** | **$ 2,989,979** | [redacted] | **$ 44,613** | **$ 608,336** | **$ 3,584** | [redacted] |

**Financial Accounting Purposes**

| | | Officer SERP | | | Restoration Plan | | | |
|---|---|---|---|---|---|---|---|---|
| | [redacted] | LG&E | ServCo | [redacted] | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | [redacted] | $ 0 | $ 208,090 | [redacted] | $ 6,691 | $ 208,975 | $ 966 | [redacted] |
| 2. Interest cost | [redacted] | 164,423 | 2,204,880 | [redacted] | 24,951 | 244,617 | 2,317 | [redacted] |
| 3. Expected return on assets | [redacted] | 0 | 0 | [redacted] | 0 | 0 | 0 | [redacted] |
| 4. Amortizations: | | | | | | | | |
| a. Transition | [redacted] | 0 | 0 | [redacted] | 0 | 0 | 0 | [redacted] |
| b. Prior service cost | [redacted] | 0 | (59,844) | [redacted] | 6,998 | 118,056 | 17 | [redacted] |
| c. Gain/loss | [redacted] | 16,971 | 318,428 | [redacted] | 4,622 | 31,908 | 0 | [redacted] |
| **5. Net periodic pension cost** | [redacted] | **$ 181,394** | **$ 2,671,554** | [redacted] | **$ 43,262** | **$ 603,556** | **$ 3,300** | [redacted] |

## 2008 Pension Cost for Qualified Plans

**IFRS Accounting Purposes**

| | | NonUnion Retirement Plan | | | |
|---|---|---|---|---|---|
| | LG&E Union | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | $ 2,744,056 | $ 2,201,011 | $ 8,911,696 | $ 5,465,928 | |
| 2. Interest cost | 16,111,005 | 11,181,199 | 12,473,629 | 18,275,304 | |
| 3. Expected return on assets | (19,974,817) | (12,458,381) | (11,659,904) | (20,896,613) | |
| 4. Amortizations: | | | | | |
| a. Transition | 0 | 0 | 0 | 0 | |
| b. Prior service cost | 0 | 0 | 0 | 0 | |
| c. Gain/loss | 0 | 0 | 0 | 0 | |
| **5. Pension cost** | **$ (1,119,756)** | **$ 923,829** | **$ 9,725,421** | **$ 2,844,619** | |

## 2008 Pension Cost for Non-Qualified Plans

| | | Officer SERP | | | Restoration Plan | | | |
|---|---|---|---|---|---|---|---|---|
| | [redacted] | LG&E | ServCo | [redacted] | LG&E | ServCo | KU | [redacted] |
| 1. Service cost | | $ 0 | $ 208,090 | | $ 6,691 | $ 208,975 | $ 966 | |
| 2. Interest cost | | 164,423 | 2,204,880 | | 24,951 | 244,617 | 2,317 | |
| 3. Expected return on assets | | 0 | 0 | | 0 | 0 | 0 | |
| 4. Amortizations: | | | | | | | | |
| a. Transition | | 0 | 0 | | 0 | 0 | 0 | |
| b. Prior service cost | | 0 | 0 | | 0 | 0 | 0 | |
| c. Gain/loss | | 0 | 0 | | 0 | 0 | 0 | |
| **5. Pension cost** | | **$ 164,423** | **$ 2,412,970** | | **$ 31,642** | **$ 453,592** | **$ 3,283** | |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 24**

**Responding Witness: Valerie L. Scott**

Q-24. Refer to pages 4 and 12 of the Scott Testimony and Reference Schedule 1.17 of Exhibit 1 to the Rives Testimony. Provide the calculations, workpapers, etc., which show the derivation of the "post-employment expenses per 2008 Mercer Study" shown on Line 2 of the reference schedule.

A-24. See attached for calculation of the derivation of the post-employment expenses annualized at 24(1) and the Mercer study on 2008 Post-Employment (SFAS No. 112) Expense for Retirement Plans at 24(4). An error was identified in the calculation of the ratio of expense to total post-employment costs. We have also provided the requested schedule using the correct expense/capital ratio (see 24(2)) and a revised Exhibit 1, Reference Schedule 1.17 (see 24(3)). The corrected Reference Schedule 1.17 reflects a decrease in expense for the pro forma adjustment of $21,253 for electric operations and $5,650 for gas operations.

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Post-Employment (SFAS 112) Benefits Expense Annualization**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1 | Company O&M SFAS No. 112 expense (excluding Servco) | | $ (33,124) | |
| 2 | Total Company SFAS No. 112 costs (excluding Servco) | | (36,524) | |
| 3 | % O&M to total | (Line 1/Line 2) | 90.69% | |
| 4 | Servco O&M SFAS No. 112 expense charged to LG&E | | | $ (215,605) |
| 5 | Total Servco SFAS No. 112 costs charged to LG&E | | | (279,549) |
| 6 | % O&M to total | (Line 4/Line 5) | | 77.13% |
| 7 | 2008 Estimated Year End SFAS No. 112 Liability per Mercer Study[1] | | $ 3,966,429 | $ 1,112,017 |
| 8 | 2007 SFAS No. 112 Liability per Mercer Study[2] | | 3,550,710 | 623,662 |
| 9 | 2008 SFAS No. 112 Benefits Cost From Increased Liability | (Line 7 - Line 8) | $ 415,719 | $ 488,355 |
| 10 | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 11 | Expected O&M expenses | (Line 6, Line 6 x Line 9) | $ 377,016 | $ 376,668 |
| 12 | Servco O&M charged to LG&E | (Line 10 x Line 11 Servco) | 158,569 | |
| 13 | Total O&M costs for 2008 Mercer target | (Line 11 + Line 12) | $ 535,585 | |

[1] For the 2008 Mercer Study, see attachment to Question No. 55, page 3 of 4, from the Commission Staff's first data request in this case.
[2] See attached 2007 Mercer Study, page 2 of 9

**Louisville Gas and Electric Company**
**Case No. 2007-00564**
**Case No. 2008-00252**

**Post-Employment (SFAS 112) Benefits Expense Annualization - Corrected for Change in Capitalization Rate**

| | | | LG&E | Servco |
|---|---|---|---|---|
| 1 | Company O&M SFAS No 112 expense (excluding Servco) | | $ (33,124) | |
| 2 | Total Company SFAS No 112 costs (excluding Servco) | | (39,331) | |
| 3 | % O&M to total | (Line 1/Line 2) | 84.22% | |
| 4 | Servco O&M SFAS No 112 expense charged to LG&E | | | $ (215,605) |
| 5 | Total Servco SFAS No 112 costs charged to LG&E | | | (279,549) |
| 6 | % O&M to total | (Line 4/Line 5) | | 77.13% |
| 7 | 2008 Estimated Year End SFAS No. 112 Liability per Mercer Study[1] | | $ 3,966,429 | $ 1,112,017 |
| 8 | 2007 SFAS No 112 Liability per Mercer Study[2] | | 3,550,710 | 623,662 |
| 9 | 2008 SFAS No 112 Benefits Cost From Increased Liability | (Line 7 - Line 8) | $ 415,719 | $ 488,355 |
| 10 | Servco % allocated to LG&E based on labor split | | | 42.1% |
| 11 | Expected O&M expenses | (Line 3, Line 6 x Line 9) | $ 350,113 | $ 376,668 |
| 12 | Servco O&M charged to LG&E | (Line 10 x Line 11 Servco) | 158,569 | |
| 13 | Total O&M costs for 2008 Mercer target | (Line 11 + Line 12) | $ 508,682 | |

[1] For the 2008 Mercer Study, see attachment to Question No. 55, page 3 of 4, from the Commission Staff's first data request in this case.
[2] See attached 2007 Mercer Study, page 2 of 9

## LOUISVILLE GAS AND ELECTRIC COMPANY

**Revised**
**Adjustment for Post-Employment Benefits**
**For the Twelve Months Ended April 30, 2008**

| | | Proforma per Filing | Revised Amount | Difference |
|---|---|---|---|---|
| 1. Post-Employment Benefits expenses in test year | | $ (248,729) | $ (248,729) | $ - |
| 2. Post-Employment expenses per 2008 Mercer Study | | 535,585 | 508,682 | 26,903 |
| 3. Total adjustment (Line 2 - Line 1) | | $ 784,314 | $ 757,411 | $ 26,903 |
| 4. Electric Department (a) | 79% | $ 619,608 | $ 598,355 | $ 21,253 |
| 5. Gas Department (a) | 21% | 164,706 | 159,056 | 5,650 |
| 6. Total Adjustment | | $ 784,314 | $ 757,411 | $ 26,903 |

(a) Percentages taken from Reference Schedule 1.15

**Marcie S. Gunnell, ASA, MAAA**
Principal

462 South Fourth Street, Suite 1100
Louisville, KY 40202
502 561 4622 Fax 502 561 4700
marcie.gunnell@mercer.com
www.mercer.com

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN

December 21, 2007

Mr. Chris Garrett
E.ON U.S. LLC
220 West Main Street
Louisville, KY 40232

**Confidential**

**Subject:** FAS 112 Liability as of December 31, 2007

Dear Chris:

The purpose of this letter is to provide you with the liabilities resulting from the valuation associated with post employment benefits for disabled employees of E.ON U.S. LLC under Statement of Financial Accounting Standards No. 112 (FAS 112). FAS 112 defines accounting standards for employer-provided benefits which are paid after active employment ceases but before retirement, whether or not the employee is expected to return to work.

The post employment benefit obligation, calculated in accordance with FAS 112 as of December 31, 2007 with a 5.95% discount rate, is a liability of $10,703,486. The liabilities and participant counts by division are shown below. These figures may be revised if liabilities are remeasured during the year due to a plan amendment, changes in assumptions or other significant event.

| | Liability | | | |
|---|---|---|---|---|
| **Division** | **Prior to Medicare Part D** | **Subsidy** | **With Medicare Part D** | **Counts** |
| LG&E | $ 3,762,588 | $ 211,878 | $ 3,550,710 | 83 |
| Kentucky Utilities | 5,349,374 | 282,973 | 5,066,401 | 106 |
| ServCo | 672,807 | 49,145 | 623,662 | 10 |
| [redacted] | | | | |

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN



The decrease in the liability over the prior valuation is due to an increase in the discount rate from 5.40% to 5.95%, a decrease in claims costs for non-disabled dependents and a decrease in the number of non-disabled dependents.

FAS 112 requires a "terminal accrual" accounting method, under which the cost of benefits is recognized in full generally at the time of termination from employment. For purposes of this valuation, we valued those individuals who were disabled as of November, 2007. The liability reflects expected savings from the 28% prescription drug subsidy under the Medicare Prescription Drug, Improvement and Modernization Act of 2003 for the disabled employees eligible or expected to be eligible for Medicare. We project that E.ON U.S. LLC will qualify for the subsidy indefinitely beginning in 2008.

The FAS 112 liability includes the actuarial present value of continued medical benefits and life insurance for each disabled employee and their dependents until the disabled's age 65, when the FAS 112 benefit terminates (benefits beyond age 65 are accounted for under FAS 106).

MERCER

MARSH MERCER KROLL
GUY CARPENTER OLIVER WYMAN



Please distribute copies of this report to the appropriate parties. Please call me at 502 561 4622 or Patrick Baker at 502 561 4504 if you have any questions.

Sincerely,

Marcie S Gunnell

Marcie S. Gunnell, A.S.A., M.A.A.A.
Principal

Copy:
Becky Smith, Heather Metts, Cathy Shultz, Henry Erk, Linda Myers, Patrick Baker

Enclosure

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**The information contained in this document (including any attachments) is not intended by Mercer to be used, and it cannot be used, for the purpose of avoiding penalties under the Internal Revenue Code that may be imposed on the taxpayer.**

# Certification

We have prepared an actuarial valuation of the postemployment benefits provided to disabled employees by E ON U.S. LLC as of December 31, 2007. The results of the valuation are set forth in this report, which reflects the provisions of the postemployment benefits plan effective December 31, 2007

This report has been prepared exclusively for E ON U.S LLC to present accounting results under FAS Nos. 112. Mercer is not responsible for consequences arising from the use of any elements of this report for any other than their intended purpose. Determinations for other purposes may be significantly different from the results shown in this report.

## Data

We have also used and relied upon participant data provided by the company. We have reviewed this data for reasonableness but have not completed an audit of this information. We have also used and relied upon the plan information supplied by the plan sponsor. The plan sponsor is solely responsible for the validity and completeness of this information.

## Accounting results

The accounting calculations reported herein are consistent with our understanding of E ON U.S. LLC's interpretation of the provisions of FAS Nos. 112. The actuarial assumptions were selected by the company. We believe that each of these assumptions is reasonable.

## Professional qualifications

We are available to answer any questions on the material contained in the report, or to provide explanations or further details as may be appropriate. Collectively, the undersigned credentialed actuaries meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinion contained in this report. We are not aware of any relationship, including investments or other services that could create a conflict of interest, that would impair our objectivity.

Marcie S Gunnell 12/21/2007

**Marcie S. Gunnell, A.S.A., M.A.A.A.** **Date**

Reviewed By:

12-21-2007

**Alan J. Craig, F.S.A., M.A.A.A.** **Date**

December 2007
Mercer
462 South Fourth Street, Suite 1100
Louisville, KY 40202-3431
Phone No. 502 561 4500

# Actuarial Basis

## Accounting Policies

FAS 112 requires a "terminal accrual" accounting method, under which the cost of benefits is recognized (in full) generally at the time of termination from employment

## Valuation Procedures

**Financial and census data:** The valuation is based on participant data as of November, 2007 provided by E.ON U.S. LLC. Although we have reviewed this data for reasonableness, we have not performed an audit of the data.

### Method Changes Since the Prior Valuation

None.

## Assumption Changes Since the Prior Valuation

- The discount rate was changed from 5.40% to 5.95%.
- The healthy mortality tables were updated from the RP 2000 combined tables for males and females with no collar adjustments projected to 2006 by Scale AA to the combined annuitant and nonannuitant mortality tables for current liability for defined benefit pension plans for the 2007 plan year as set forth in regulations section 1.412(l)(7)-1)

## Plan Provision Changes Since the Prior Valuation

None.

## Impact of the Medicare Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the MMA) was reflected as of December 8, 2003 assuming that E.ON U.S. LLC will continue to provide a prescription drug benefit to Medicare-eligible disabled employees that is at least actuarially equivalent to Medicare Part D and that E.ON U.S. LLC will receive the federal subsidy.

The following assumptions were used with the MMA calculations:

- E.ON U.S. LLC will determine actuarial equivalence by benefit option. Testing by benefit option, the Medicare-eligible disabled employees' medical drug plan is projected to meet the definition of actuarial equivalence indefinitely.
- E.ON U.S. LLC will apply for and receive the subsidy available under Medicare starting 2008 for all Medicare-eligible disabled employees that have drug coverage.
- Medicare-eligible disabled employees do not elect Medicare Part D benefit.

The estimated subsidy was based on Mercer's understanding of the Medicare Reform legislation based on the final Center for Medicare Services (CMS) regulations issued January 2005 and on the provided claims information from the medical plan administrator

# **Actuarial Basis** *(continued)*

## Summary of Actuarial Assumptions

The following assumptions were used in valuing the liabilities and benefits under the plan

| | |
|---|---|
| *Measurement Date* | December 31, 2007 |
| *Discount rate* | 5 95% |
| *Health care cost trend rates* | The trend rates of incurred claims represent the rate of increase in employer claim payments: |

| Years | Medical Annual Rates of Increase |
|---|---|
| 2007 | 9 00% |
| 2008 | 8 00% |
| 2009 | 7 00% |
| 2010 | 7 00% |
| 2011 | 6 00% |
| 2012 | 6 00% |
| 2013 | 5 50% |
| 2014 | 5 50% |
| 2015+ | 5.00% |

*Medical cost for disabled employees*

| | | |
|---|---|---|
| ▪ Before Medicare offset | $ | 17,685 |
| ▪ After Medicare offset | | 6,093 |
| ▪ Projected federal drug subsidy | | 710 |
| ▪ Healthy spouse pre-Medicare age 65 cost | | 8,036 |

*Disabled claims costs are based on 2006 and 2007 disabled claims and administrative fees, trended to the measurement date. Healthy claims costs are based on the claims costs shown in the 2007 Postretirement Benefit Plan Valuation Report trended to the measurement date.*

| | |
|---|---|
| *Medicare benefits* | Medicare is assumed to be primary in the medical plan after two years of disability and will reduce the company's cost by 70%. Certain disabled individuals were identified by the company as ineligible for Medicare benefits with no expectation that they will become Medicare eligible. It is assumed that these individuals' status will not change and that Medicare will not be primary. |
| *Administrative expenses* | Included in the per-capita claims cost for medical benefits. None for life insurance benefits. |

# **Actuarial Basis** *(continued)*

## **Summary of Actuarial Assumptions** *(continued)*

| | |
|---|---|
| *Healthy mortality* | Combined annuitant and nonannuitant mortality tables for current liability for defined benefit pension plans for the 2007 plan year as set forth in regulations section 1 412(l)(7)-1). |
| *Disabled mortality* | IRS Prescribed Tables for male and female lives disabled before 1995 See table of sample rates below. |
| *Recovery* | To reflect the probability of recovery from disability and return to active work, an adjustment factor of 92 08 percent was developed from the 1987 Commissioner's Group Disablity Table and multiplied by the present values that were calculated assuming no recovery. |
| *Other assumptions* | All other assumptions are as shown in the 2007 FAS 106 actuarial valuation report. |

Table of Sample Rates

| | Percentage | | | |
|---|---|---|---|---|
| | Mortality Disabled Lives | | Mortality Healthy Lives | |
| **Attained Age** | **Male Mortality** | **Female Mortality** | **Male Mortality** | **Female Mortality** |
| 20 | 0 76% | 0 58% | 0.02% | 0.01% |
| 25 | 0.92% | 0 72% | 0 03% | 0 02% |
| 30 | 1 12% | 0 89% | 0 04% | 0 02% |
| 35 | 1.34% | 1 09% | 0 07% | 0 04% |
| 40 | 1 60% | 1 26% | 0.09% | 0 05% |
| 45 | 1 93% | 1 44% | 0 11% | 0 08% |
| 50 | 2 36% | 1 65% | 0 16% | 0 12% |
| 55 | 2 95% | 1 91% | 0 25% | 0 23% |
| 60 | 3.62% | 2 26% | 0 52% | 0 46% |

# **Actuarial Basis** *(continued)*

## Summary of Plan Provisions

| | |
|---|---|
| **Eligibility** | Employees who are approved for LTD benefits. The elimination period is 6 months (3 months for WKE union). |
| **Medical benefits** | Eligible for continuation of the medical plans offered to active employees for themselves and eligible dependents generally until the disabled employee's age 65. Upon reaching age 65 participants are assumed to elect retirement and are covered under the terms of the retiree medical plan. |
| **Surviving spouse coverage** | Surviving spouses of deceased disabled employees are covered under the medical plan following the disabled employee's death, provided they make any required monthly premium contributions |
| **Contributions** | Disabled employees contribute toward the coverage on the same basis as active employees |
| **Life Insurance** | Eligible for continuation of the life insurance plan offered to active employees until age 65. Upon reaching age 65 participants are assumed to elect retirement and are covered under the terms of the retiree life insurance plan (if any). |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 25**

**Responding Witness: Valerie L. Scott**

Q-25. Refer to pages 4-5 of the Scott Testimony, specifically, the request to defer revenues related to MISO Schedule 10 expenses deferred between the end of the test year and the date new rates go into effect, as well as any future adjustments to the MISO exit fee, as regulatory liabilities until the amounts can be amortized as part of a future rate case.

a. Provide the amount of revenues related to MISO Schedule 10 expenses realized by LG&E during the test year and the amount of such revenues LG&E projects it will realize in the first 12 months after new rates go into effect.

b. Describe the extent of past adjustments to the MISO exit fee and the period of time over which future adjustments are reasonably anticipated to occur.

A-25. a. The amount of revenues related to the MISO Schedule 10 expenses realized by LG&E during the test year is $3,341,946.

b. There will be no revenues related to MISO Schedule 10 expenses after new rates go into effect.

A refund of $681,715 of the MISO exit fee was received in March 2008, which settled amounts owed through December 2007. Annual refund payments will continue to be received in the first quarter of each year from 2009 through 2015 for the preceding calendar year based on actual activity experienced by the MISO. Monthly accruals are being booked in the current year, reducing the MISO exit fee regulatory asset for estimated refunds to be paid in the following year. Refund accruals of $85,242 are included in the April 30, 2008 test year MISO exit fee balance in account 182321.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 26**

**Responding Witness: Valerie L. Scott**

Q-26. Refer to pages 6-7 of the Scott Testimony. Provide the 2009 date when the coal tax credit statute is to expire.

A-26. KRS 141.0406, enacted as HB 805, Chapter 320 on April 5, 2000, states that "except in the case of an alternative fuel facility as defined in KRS 154.27-010 or a gasification facility as defined in KRS 154.27-010, the Coal Incentive Credit authorized under KRS 141.0405 shall be allowed for ten (10) consecutive years beginning on July 15, 2001."

KRS 141.0405 (4) (a) states: The base year amount shall be equal to: For entities existing on July 14, 2000, that meet the eligibility requirements imposed under subsection (1) of this section, the tons of coal purchased and used to generate electricity during the twelve (12) calendar months ending in December 31, 1999, that were subject to the tax imposed by KRS 143.020

The calendar year of 2000 was the first period whereby Kentucky coal purchases in excess of 1999 base year levels were eligible for the $2 per ton credit. Given the ten year period in the statute, coal purchases in 2009 (through December 31, 2009) will be the final year in which Kentucky coal purchases will be eligible for the coal tax credit. An application for 2009 must be submitted for approval by the Department of Revenue by March 15, 2010 for use on either the Company's 2009 Kentucky Income Tax Return or its 2010 Kentucky Property Tax Return.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 27

Responding Witness: John J. Spanos

Q-27. Refer to Volume 4 of 5 of LG&E's application, the Testimony of Shannon L. Charnas ("Charnas Testimony"), at page 3; Reference Schedule 1.14 of Exhibit 1 to the Rives Testimony; and the Joint Rebuttal Testimony of John J. Spanos ("Spanos Rebuttal"), pages 2 through 4, filed in Case No. 2007-00564.

a. Explain how Mr. Spanos's example would be affected if the hypothetical utility performed depreciation studies every 4 years and remaining service life was considered as part of those studies.

b. Assume for purposes of this question that Unit A in Mr. Spanos's example actually remains in service for 6 years and Unit B actually remains in service 12 years. Explain how these additional assumptions would affect Mr. Spanos's example comparing the average service life approach with the equal life group approach.

c. The Spanos Rebuttal often notes that the equal life group approach is the most accurate approach and provides the better match of recovery to consumption. Are there other reasons or events which have occurred at LG&E within the last 5 years that support the adoption and use of the equal life group approach? If yes, describe those reasons or events in detail.

d. As part of the depreciation study, did Mr. Spanos perform a comparison of the theoretic depreciation reserve with the actual depreciation reserve?

(1) If yes, what were the results of this comparison? Describe the actions, if any, resulted from the comparison.

(2) If no, explain why such a comparison was not performed.

A-27. a. There are many variables to take into consideration when attempting to utilize the two unit example on pages 2 through 4 of Mr. Spanos' rebuttal testimony in a ratemaking scenario. For example, service life decisions will be reevaluated for the account and reserve-to-plant ratios are left out of the formula. Thus, the purpose of the two unit example is to describe and compare the two depreciation procedures: average service life and equal life group.

Consequently, all of the variables must be resolved or determined to be able to properly respond to the affects to the two unit example in the regulatory environment.

b. The change to the example would produce an average service life of 9 years, rate of 11.11%, and annual depreciation amount of approximately $222. At the end of year 6, the accumulated depreciation would be $332 or 33% of the Unit B value; however, it has survived two-thirds of life. In the equal life group procedure, Unit A would have a 16.67% rate and Unit B would have a 8.33% rate. Thus, after year 6, the accumulated depreciation would be $500, which is half of the recovery of Unit B with half of its service life remaining.

c. No, there are no other reasons or events which have occurred at LG&E within the last 5 years that require the adoption of the equal life group procedure. It is Mr. Spanos' opinion that the equal life group procedure is the most accurate approach so it should be implemented.

d. (1) Yes, a comparison of the theoretical reserve to the actual reserve was performed. However, it must be understood that the theoretical depreciation reserve is a measure of past recovery assuming the same life and salvage parameters were in place from the first day of installation which is not realistic for long-lived assets and utilities that have rate cases.

The comparison of the theoretical reserve to the actual reserve is part of the depreciation calculation in Mr. Spanos' Depreciation Study. The detailed calculations are presented on pages III-428 through III-628 of the Depreciation Study.

(2) Not applicable.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 28**

**Responding Witness: Lonnie E. Bellar / John J. Spanos**

Q-28. Refer to the response to the Commission Staff's Second Data Request dated April 14, 2008 in Case No. 2007-00565, Item 3, wherein KU indicated that it was reviewing the recommendations of the Virginia State Corporation Commission ("Virginia SCC") Staff, which rejected the use of the equal life group approach.

a. Provide the status of KU's review of the Virginia SCC Staff's recommendations and describe how KU has determined it will proceed in response.

b. The Virginia SCC Staff cited several concerns related to switching to the equal life group approach. Provide a response for each concern listed below.

(1) Average service life approach tends to produce more stable rates, all other variables being equal.

(2) A switch to the equal life group approach can compound any inaccuracies in estimation of the retirement dispersion.

(3) A switch to the equal life group approach can introduce inter-generational inequities.

(4) A switch to the equal life group approach can be more costly and time-consuming to maintain.

A-28. a. The letter is an administrative recommendation by the VSCC Accounting Division. It does not bind the Virginia Commission. KU expects to contest the recommendation in its next rate case.

b. The Virginia State Corporation Commission did not review any studies for Louisville Gas & Electric Company as there are no assets in their jurisdiction. However, the four issues listed above have been addressed for Kentucky Utilities assets in response to Question No. 89 in Case No. 2008-00251.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 29**

**Responding Witness: Counsel**

Q-29. LG&E and KU jointly own 10 combustion turbines ("CTs"). The CTs are Paddy's Run – Generator 13, E. W. Brown CTs 5 through 7, and Trimble County CTs 5 through 10. The proposed depreciation rates for these 10 CTs are not the same for KU and LG&E. Recalculate LG&E's proposed depreciation expense adjustment reflecting the KU proposed depreciation rates for the E. W. Brown CTs 5 through 7 and the LG&E proposed depreciation rates for Paddy's Run – Generator 13 and Trimble County CTs 5 through 10.

A-29. The requests seek a calculation using incorrect rates for the CTs which requires original work and that, if completed, and used for ratemaking purposes, would be confiscatory. It is inappropriate to calculate depreciation expense on LG&E assets using KU depreciation rates as the methodology of KU depreciation rates have not historically been consistent with LG&E's past depreciation recovery of those assets. Though the units are the same they have not been recovered in the past at the same rate so future recovery amounts are different as well. All of the generating units utilize individual depreciation rates assigned by company based on original cost and accumulated depreciation, not location only. Applying KU depreciation rates to LG&E's assets would not guarantee full recovery of these assets, as required.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 30**

**Responding Witness: Counsel / Shannon L. Charnas / John J. Spanos**

Q-30. Provide a recalculation of LG&E's proposed depreciation expense adjustment based upon the following assumptions.

a. Depreciation expense is calculated utilizing the depreciation rates provided by LG&E in response to Item 27 of the AG's Initial Request for Information (dated February 4, 2008) in Case No. 2007-00564. For the 10 CTs jointly owned by LG&E and KU, the recalculation should use the KU depreciation rates for the E. W. Brown CTs 5 through 7 and the LG&E depreciation rates for the Paddy's Run – Generator 13 and the Trimble County CTs 5 through 10.

b. Depreciation expense is calculated utilizing the depreciation rates proposed by the AG's witness, Michael J. Majoros, Jr. For the 10 CTs jointly owned by LG&E and KU, the recalculation should use the KU depreciation rates for the E. W. Brown CTs 5 through 7 and the LG&E depreciation rates for the Paddy's Run – Generator 13 and the Trimble County CTs 5 through 10.

A-30. a. The requests seek a calculation using incorrect rates for the CTs which requires original work and that, if completed, and used for ratemaking purposes, would be confiscatory. It is inappropriate to calculate depreciation expense on LG&E assets using KU depreciation rates as the methodology of KU depreciation rates have not historically been consistent with LG&E past depreciation recovery of those assets. Though the units are the same they have not been recovered in the past at the same rate so future recovery amounts are different as well. All of the generating units utilize individual depreciation rates assigned by company based on original cost and accumulated depreciation, not location only. Applying KU depreciation rates to LG&E's assets would not guarantee full recovery of these assets, as required. Please see LG&E's response to Question No. 29.

b. Without waiver of the objection filed on September 5, 2008, a recalculation of LG&E's proposed depreciation expense adjustment based upon the depreciation rates proposed by the AG's witness, Michael J. Majoros, Jr. is attached. For the 10 CTs jointly owned by LG&E and KU, the recalculation uses the correct depreciation rates for the E. W. Brown CTs 5 through 7 and the correct depreciation rates for the

Paddy's Run – Generator 13 and the Trimble County CTs 5 through 10. LG&E does not agree with the depreciation rates proposed by the AG's witness, Michael J. Majoros, Jr. and disputes the reasonableness of the calculation provided in this response.

**Louisville Gas & Electric Company**

**Adjustment To Reflect Annualized Depreciation Expenses Under Majoros Proposed Rates**
**At April 30, 2008**

| | Electric | Gas | Total |
|---|---|---|---|
| Annualized direct depreciation expense under Majoros proposed rates (1) | $ 72,554,971 | $ 9,939,325 | $ 82,494,296 |
| Common Plant allocated annualized depreciation expense under proposed rates (1) (2) | $ 13,392,902 | $ 4,705,614 | $ 18,098,516 |
| Total annualized depreciation expense under proposed rates | $ 85,947,873 | $ 14,644,939 | $ 100,592,812 |
| Depreciation expense per books for test year | $ 107,382,630 | $ 18,923,380 | $ 126,306,010 |
| Depreciation expense for asset retirement costs (ARO) | 179,051 | 9,103 | 188,154 |
| Depreciation for post-1995 environmental cost recovery (ECR) | 7,240,995 | - | 7,240,995 |
| Depreciation expense per books excluding ARO and post-1995 ECR | $ 99,962,584 | $ 18,914,277 | $ 118,876,861 |
| Total Adjustment to reflect annualized depreciation expense | $ (14,014,711) | $ (4,269,338) | $ (18,284,048) |

(1) Reflects Majoros proposed rates per Case No 2007-00564
(2) Common plant depreciation was allocated 74% to electric and 26% to gas pursuant to common utility plant study

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 31**

**Responding Witness: Shannon L. Charnas**

Q-31. Refer to the Charnas Testimony at pages 5-6 and 10-11. Provide with this response, and every month thereafter at the time it files its monthly financial statements with the Commission, an update on LG&E's actual rate case expenses.

A-31. The Company is providing monthly updates of its rate case expenses pursuant to PSC-1 Question No. 57 in this case.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 32**

**Responding Witness: Shannon L. Charnas**

Q-32. Refer to page 6 of the Charnas Testimony and Reference Schedule 1.28 of Exhibit 1 to the Rives Testimony.

a. Provide a detailed description of the criteria used by LG&E to determine that the cost of the lease for demineralization equipment at the Cane Run and Mill Creek generating facilities should have been recorded as a capital lease rather than an operating lease.

b. Explain in detail why LG&E initiated a review of its initial decision to record the lease as an operating lease.

c. Provide the accounting entries made when LG&E initially recorded the lease as an operating lease and those it made when it determined that it should have been recorded as a capital lease.

d. Describe the reasoning for reversing the rent expense for the duration of the lease and the adjustment to remove the impact of reversing the rent expense.

A-32. a. The Lease agreement states that at the end of the lease, LG&E can purchase the demineralization equipment for $1 which creates a bargain purchase option, one of the four criteria that determines a capital lease, in accordance with Statement of Financial Accounting Standard No. 13, *Accounting for Leases*.

b. Accounting was contacted in March 2007 by Cane Run personnel regarding the purchase of the property. The inquiry prompted the review of the lease by Accounting personnel, upon which it was determined that the lease should have been recorded as a capital lease at inception.

c. The monthly entries made from inception when LG&E was recording the lease as an operating lease were:

| | | | |
|---|---|---|---|
| DR | 502100 Steam Expense | $52,400 | |
| CR | 232100 Trade Payable | | $52,400 |

| | | | |
|---|---|---|---|
| DR | 232100 Trade Payable | $52,400 | |
| CR | 131092 Cash – BOA Funding | | $52,400 |

The entry that was made when LG&E determined the lease should have been recorded as a capital lease was:

| | | | |
|---|---|---|---|
| DR | 101101 Property Under Capital Leases | $2,876,958 | |
| DR | 427001 Interest-Notes/Debentures | $3,175,508 | |
| DR | 403002 Depreciation Expense – Whsle | $732,388 | |
| CR | 502100 Steam Expense | | $5,503,332 |
| CR | 227100 Obl Under Capital Leases – Noncurrent | | $160,832 |
| CR | 243100 Obl Under Capital Leases – Current | | $388,302 |
| CR | 108115 Accum. Depreciation – Cor-Elect Structures | | $732,388 |

d. Rent expense for the duration of the lease was reversed in order to properly establish the capital asset and the lease obligation, which, in turn, required recording depreciation and interest expense.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 33**

**Responding Witness: Shannon L. Charnas**

Q-33. Refer to pages 7 and 11 of the Charnas Testimony and Reference Schedule 1.29 of Exhibit 1 to the Rives Testimony.

a. Provide the accounting entries made in July 2007 to correct the accounting for LG&E's Information Technology maintenance contracts.

b. Provide the calculations, workpapers, etc., that show the derivation of the proper amount of expense for the contracts during the test year.

A-33. a. The accounting entry prepared by LG&E to correct the accounting for the IT contract follows:

| | | |
|---|---|---|
| Debit 146100 INTERCOMPANY - SERVCO | $1,313,131.37 | |
| Credit 935488 MTC-OTH GEN EQ – INDIRECT | | $1,313,131.37 |

b. See the attached schedule showing the derivation of the $2,224,837, the proper amount of expense for the IT contracts during the test year. All IT contracts are held by Servco and allocated to LG&E based on the IT departmental allocation of 47.99%.

## Current Test Year Annual Cost for IT Contracts

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| AASTRA USA INC | Maintenance for Intecom Switch Software for Phone Service | JUN-07 | 5/07-4/08 | $ 123,490.00 |
| ACTUATE CORP | Maintenance for Web Reporting Development Tool Software | DEC-06 | 1/07-12/07 | - |
| ACTUATE CORP | Maintenance for Web Reporting Development Tool Software | DEC-07 | 12/07-11/08 | 40,228.03 |
| ADVANCED SOFTWARE PRODUCTS GRP | Maintenance for Mainframe Software | JUN-06 | 7/06-6/07 | - |
| ADVANCED SOFTWARE PRODUCTS GRP | Maintenance for Mainframe Software | JUN-07 | 7/07-6/08 | 4,663.33 |
| ADVANCED SOLUTIONS INC | Maintenance for AutoCAD Software | JAN-07 | 1/07-12/07 | (0.00) |
| ADVANTICA INC | Maintenance for Distribution System Analysis Software | DEC-06 | 12/06-11/07 | - |
| ADVANTICA INC | Maintenance for Distribution System Analysis Software | DEC-07 | 12/07-11/08 | 26,626.56 |
| ADVANTICA INC | Maintenance for Distribution System Analysis Software | NOV-06 | 11/06-10/07 | - |
| AGILYSYS | Maintenance for HP Hardware | DEC-07 | 12/07 | 9,044.03 |
| AGILYSYS | Maintenance for Storage Software and Equipment | SEP-07 | 9/07 | 4,983.30 |
| AGILYSYS | Maintenance on Channel Extension Equipment | DEC-07 | 12/07 | 14,061.82 |
| AGILYSYS | Maintenance on Channel Extension Equipment | DEC-07 | 12/07-11/08 | 2,205.07 |
| AGILYSYS Total | Maintenance for Software used for server management | JUL-07 | 7/07 | 23,117.36 |
| ALG SOFTWARE | Maintenance for Financial Reporting Software | OCT-06 | 12/06-11/07 | - |
| AMERICAN INNOVATIONS LTD | Maintenance for Software for Pipeline Integrity for Distribution | OCT-06 | 11/06-10/07 | - |
| AMERICAN INNOVATIONS LTD | Maintenance for Software for Pipeline Integrity for Distribution | OCT-07 | 11/07-10/08 | 8,372.50 |
| APOGEE INTERACTIVE INC | Maintenance for Commercial Calculator Software for Customer Self Service | FEB-08 | 2/08-12/08 | 1,750.36 |
| APOGEE INTERACTIVE INC | Maintenance for Residential Calculator Software for Customer Self Service | FEB-08 | 2/08-12/08 | 9,136.36 |
| APPLIED FLOW TECHNOLOGY CORP | Maintenance for Software used by Power Generation to analyze and control fluid flow | OCT-07 | 10/07 | 400.00 |
| APRISO CORP | Maintenance for Barcoding Software | FEB-07 | 3/07-2/08 | 0.00 |
| APTARE INC | Maintenance for Reporting Tool for Backup Software | AUG-07 | 8/07 | 310.64 |
| APTARE INC | Maintenance for Reporting Tool for Backup Software | FEB-07 | 1/07-12/07 | - |
| ASPECT COMMUNICATIONS CORP | Maintenance for EWFM Software for Retail Call Center | APR-08 | 4/08-1/09 | 1,561.60 |
| ASPECT COMMUNICATIONS CORP | Maintenance for EWFM Software for Retail Call Center | FEB-08 | 2/08-1/09 | 3,904.00 |
| AVAYA INC | Maintenance for the Conference Bridge Software | MAY-07 | 2/07-1/08 | 3,999.96 |
| AVAYA INC | Maintenance for the Conference Bridge Software] | JUL-07 | 7/07 | 288.00 |
| BENTLEY SYSTEMS INC | Maintenance for Version Management Software | DEC-06 | 12/06-11/07 | - |
| BENTLEY SYSTEMS INC | Maintenance for Version Management Software | DEC-07 | 12/07 | 18,800.60 |
| BERBEE INFORMATION NETWORKS CORPORATION | Maintenance for Mainframe Software | JAN-07 | 1/07-12/07 | 0.00 |
| BERBEE INFORMATION NETWORKS CORPORATION | Maintenance for Mainframe Software | OCT-06 | 10/06-09/07 | - |
| BLACKBERRY MADE SIMPLE | Customization of training video for E.ON US IT Training | OCT-07 | 10/07 | 200.00 |
| BLACKBERRY MADE SIMPLE | Purchase of software license for training video for E.ON US IT Training | OCT-07 | 10/07 | 2,995.00 |
| BLADELOGIC INC | Maintenance for Server Management Software | DEC-07 | 12/07-11/08 | 25,114.96 |
| BMC FINANCIAL SERVICES CO | Maintenance for Mainframe Software | JUN-07 | 6/07-5/08 | 33,916.67 |
| BMC FINANCIAL SERVICES CO | Maintenance for Service Desk Software | JUN-06 | 7/06-6/07 | - |
| BMC SOFTWARE DISTRIBUTION INC | Maintenance for Service Desk Software | APR-07 | 4/07-3/08 | - |
| CA INC | Maintenance for Mainframe Job Scheduler Software | DEC-07 | 12/07-11/08 | 17,987.20 |
| CA INC | Maintenance for Mainframe Job Scheduler Software | FEB-07 | 1/07-12/07 | - |
| CA INC | Maintenance for Mainframe Job Scheduler Software | JAN-07 | 1/07-12/07 | - |
| CA INC | Maintenance for Mainframe Software | DEC-07 | 12/07-11/08 | 148,309.66 |
| CA INC | Maintenance for Mainframe Software | JAN-07 | 1/07-12/07 | - |

## Current Test Year Annual Cost for IT Contracts

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| CADRE COMPUTER RESOURCES CO | Maintenance and Subscription for Internet Security Systems applicance for Security | DEC-06 | 1/07-12/07 | - |
| CADRE COMPUTER RESOURCES CO | Maintenance and Subscription for Internet Security Systems applicance for Security | OCT-06 | 10/06-09/07 | - |
| CADRE COMPUTER RESOURCES CO | Maintenance for Bluecoat Appliances and Software for Security | DEC-07 | 1/08-12/08 | 7,350.28 |
| CADRE COMPUTER RESOURCES CO | Maintenance for Bluecoat Appliances and Software for Security | DEC-07 | 12/07-11/08 | 1,859.81 |
| CADRE COMPUTER RESOURCES CO | Maintenance for Desktop Security Software | DEC-06 | 12/06-11/07 | - |
| CADRE COMPUTER RESOURCES CO | Maintenance for Firewall Software | NOV-07 | 11/07-10/08 | 11,861.45 |
| CADRE COMPUTER RESOURCES CO | Maintenance for Firewall Software | OCT-07 | 10/07 | 21,298.75 |
| CADRE COMPUTER RESOURCES CO | Maintenance for Firewall Software | SEP-06 | 11/06-10/07 | - |
| CALAMP SOLUTIONS INC | Maintenance for Software that provides alerts from Network Mgmt Systems | AUG-07 | 8/07 | 1,600.00 |
| CHICAGO SOFT LTD | Maintenance for Mainframe Software | AUG-06 | 10/06-09/07 | - |
| CHICAGO SOFT LTD | Maintenance for Mainframe Software | SEP-07 | 9/07 | 5,400.00 |
| CINCINNATI BELL TECHNOLOGY SOLUTIONS | Maintenance and Subscription for Internet Security Systems applicance for Security | JAN-08 | 1/08 | 8,776.93 |
| CINCINNATI BELL TECHNOLOGY SOLUTIONS | Maintenance and Subscription for Internet Security Systems applicance for Security | JAN-08 | 1/08-12/08 | 46,725.79 |
| CIPHERTRUST INC | Maintenance for e-mail filtering hardware | JAN-07 | 1/07-7/07 | - |
| CIPHERTRUST INC | Maintenance for e-mail filtering hardware | JUL-06 | 7/06-6/07 | - |
| CITRIX SYSTEMS INC | Maintenance for Citrix Software | AUG-07 | 8/07-7/08 | 12,187.50 |
| CITRIX SYSTEMS INC | Maintenance for Citrix Software | OCT-06 | 9/06-8/07 | - |
| COADE INC | Maintenance for Software used by Engineering as a Piping Design and Drafting Program | SEP-07 | 9/07 | 500.00 |
| COGNOS CORP | Maintenance for Adhoc Reporting Software | SEP-07 | 9/07-5/08 | 8,565.33 |
| COMPUWARE CORP | Maintenance for Mainframe Software | JUN-06 | 7/06-6/07 | - |
| COMPUWARE CORP | Maintenance for Mainframe Software | JUN-07 | 6/07-5/08 | 71,225.00 |
| COMWARE SYSTEMS INC | Maintenance for the Telephone Management Software | JUN-06 | 6/06-5/07 | - |
| COMWARE SYSTEMS INC | Maintenance for the Telephone Management Software | JUN-07 | 6/07-5/08 | 15,153.88 |
| CONVERGENT GROUP CORP | Maintenance for Outage Management Software | FEB-08 | 2/08 | 10,450.00 |
| CONVERGENT GROUP CORP | Maintenance for Outage Management Software | JAN-07 | 1/07-12/07 | 0.00 |
| COURION CORP | Maintenance for the Password Reset Software | AUG-06 | 9/06-8/07 | - |
| COURION CORP | Maintenance for the Password Reset Software | SEP-07 | 9/07 | 482.87 |
| COURION CORP | Maintenance for the Password Reset Software | SEP-07 | 9/07-5/08 | 4,444.33 |
| COURION CORP | Maintenance for the Password Reset Software | SEP-07 | 9/07-8/08 | 4,556.84 |
| DATA PROCESSING SCIENCES CORP | Maintenance for RSA Server | APR-07 | 5/07-4/08 | - |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance for Imaging Software | DEC-06 | 1/07-12/07 | - |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance for Imaging Software | JAN-08 | 1/08-12/08 | 15,811.05 |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance for Imaging Software | MAY-07 | 1/07-12/07 | 10,875.00 |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance for Scanners and Jukebox for Imaging System | APR-07 | 1/07-12/07 | 0.00 |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance for Scanners and Jukebox for Imaging System | DEC-07 | 1/08-12/08 | 5,424.35 |
| DOCUMENT CONTROL SYSTEMS INC | Maintenance on Imaging Software | JAN-08 | 1/08-12/08 | 3,509.00 |
| DOCUMENT CONTROL SYSTEMS INC | Payment for Services for Imaging Extraction | AUG-07 | 8/07 | 1,525.00 |
| DOLBEY AND CO | Maintenance for Call Recording Equipment | DEC-06 | 12/06-11/07 | - |
| DOLBEY AND CO | Maintenance for Call Recording Equipment | JUL-07 | 7/07 | 3,600.00 |
| DOLBEY AND CO | Maintenance for Call Recording Equipment | SEP-06 | 7/06-6/07 | - |
| EMBARCADERO TECHNOLOGIES INC | Maintenance for database software tools | JAN-07 | 1/07-9/07 | - |
| EMBARCADERO TECHNOLOGIES INC | Maintenance for database software tools | OCT-07 | 10/07 | 5,800.00 |

**Current Test Year Annual Cost for IT Contracts**

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| EMC CORP | Maintenance for Mainframe Hardware | JUL-07 | 7/07 | 17,258.07 |
| EMC CORP | Maintenance for Mainframe Software | MAY-07 | 2/07-1/08 | 13,674.00 |
| EON | Maintenance for Cryptoguide Security Software | AUG-07 | 8/07 | 790.70 |
| EON | Maintenance for Cryptoguide Security Software | JUN-07 | 6/07 | 660.97 |
| EON | Maintenance for Public Key Infrastructure Security Software | AUG-07 | 8/07 | 10,657.32 |
| EON | Maintenance for Public Key Infrastructure Security Software | DEC-07 | DEC-2007 | 4,413.53 |
| EON | Maintenance for Public Key Infrastructure Security Software | JUN-07 | 6/07 | 9,830.66 |
| EON | Maintenance for Risk Management System Software | DEC-07 | DEC-2007 | 9,858.57 |
| EXCALIBUR INTEGRATED SYSTEMS INC | Maintenance for Security Software | JAN-07 | 1/07-12/07 | - |
| FILENET CORP | Maintenance for Imaging Software | JUN-07 | 6/07 | 3,644.00 |
| FILENET CORP | Maintenance for Imaging Software | MAY-07 | 5/07 | 3,644.00 |
| GE ENERGY MANAGEMENT SERVICES INC | Maintenance for Smallworld Geospatial Information System | FEB-08 | 2/08-12/08 | 88,434.00 |
| GE ENERGY MANAGEMENT SERVICES INC | Maintenance for Smallworld Geospatial Information System | JUN-07 | 6/07 | 11,002.50 |
| GE ENERGY MANAGEMENT SERVICES INC | Maintenance for Smallworld Geospatial Information System | MAR-07 | 1/07-12/07 | (28,795.58) |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | APR-08 | 6/08-8/08 | - |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | JAN-07 | 3/07-5/07 | - |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | JAN-08 | 3/08-5/08 | 4,498.40 |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | JUL-07 | 6/07 - 8/07 | 9,240.00 |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | MAY-07 | 6/07-8/07 | 10,365.00 |
| GLOBALVIEW SOFTWARE INC | Subscription for Energy Marketing | NOV-07 | 12/07-2/08 | 11,685.00 |
| GROUP 1 SOFTWARE | Maintenance for Enterprise Bill Print Software | MAR-08 | 4/08-3/09 | 5,061.92 |
| GT SOFTWARE INC | Maintenance for Mainframe Software | JAN-07 | 1/07-12/07 | 0.00 |
| GT SOFTWARE INC | Maintenance for Mainframe Software | JAN-08 | 1/08 | 11,758.86 |
| GUARDIUM INC | Maintenance for Guardium Database Monitoring Software | FEB-08 | 2/08-1/09 | 1,066.01 |
| GUARDIUM INC | Maintenance for Guardium Database Monitoring Software | JAN-07 | 1/07-12/07 | - |
| HEWLETT PACKARD | Maintenance for Guardium Database Monitoring Software | FEB-07 | 10/06-9/07 | - |
| HEWLETT PACKARD | Maintenance for Monitoring Software | MAY-07 | 5/07-4/08 | 40,710.60 |
| HEWLETT PACKARD | Maintenance for Purge Archive Software for Oracle | JUL-07 | 3/07-2/08 | 14,745.27 |
| HEWLETT PACKARD | Maintenance for Server | JAN-08 | 1/08-9/08 | 195,337.02 |
| IBM CORPORATION | Maintenance for Imaging Software | NOV-07 | 7/07-6/08 | 35,839.99 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | APR-08 | 4/08 | 4,506.22 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | AUG-07 | 8/07 | 17,107.00 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | DEC-07 | 12/07 | 4,506.22 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | FEB-08 | 2/08 | 4,506.22 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | JAN-08 | 1/08 | 4,506.22 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | JUL-07 | 07/07 | 17,107.00 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | JUN-07 | 6/07 | 21,316.00 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | MAR-08 | 3/08 | 4,506.22 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | MAY-07 | 5/07 | 21,316.00 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | OCT-07 | 10/07 | 20,299.00 |
| IBM CORPORATION | Maintenance for Mainframe Database Software | SEP-07 | 9/07 | 18,072.00 |
| IBM CORPORATION | Maintenance for Mainframe Hardware | AUG-07 | 8/07 | 2,794.71 |

**Current Test Year Annual Cost for IT Contracts**

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| IBM CORPORATION | Maintenance for Mainframe Hardware | JUN-07 | 6/07 | 2,794.71 |
| IBM CORPORATION | Maintenance for Mainframe Software | APR-08 | 4/08 | 27,844.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | AUG-07 | 8/07 | 15,479.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | DEC-07 | 12/07 | 44,656.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | FEB-08 | 2/08 | 27,844.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | JAN-08 | 1/08 | 27,844.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | JUL-07 | 07/07 | 15,479.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | JUN-07 | 6/07 | 11,270.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | MAR-08 | 3/08 | 27,844.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | MAY-07 | 5/07 | 11,270.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | OCT-07 | 10/07 | 14,514.00 |
| IBM CORPORATION | Maintenance for Mainframe Software | SEP-07 | 9/07 | 14,514.00 |
| INFOGIX INC | Maintenance for Mainframe Software | JUL-06 | 7/06-6/07 | - |
| INFOGIX INC | Maintenance for Mainframe Software | JUL-07 | 7/07-6/08 | 14,305.95 |
| INFORMATION INTELLECT INC | Maintenance for Tax Software | MAY-07 | 5/07-4/08 | 28,001.00 |
| INFOTEL CORP | Maintenance for Mainframe Database Software | OCT-06 | 10/06-9/07 | - |
| INFOTEL CORP | Maintenance for Mainframe Database Software | SEP-07 | 9/07 | 6,093.45 |
| INNOVATION DATA PROCESSING INC | Maintenance for Customer Infromation System Software | APR-07 | 5/07-4/08 | - |
| INTERMEC TECHNOLOGIES CORP | Maintenance for Barcode Printers | JAN-07 | 1/07-12/07 | - |
| INTERMEC TECHNOLOGIES CORP | Maintenance for Barcode Printers | OCT-07 | 10/07 | 13,728.00 |
| IRON MOUNTAIN INTELLECTUAL PROPERTY MGMT INC | Escrow Fees for the Source Code to the Convergent Model Office Software | JUL-07 | 7/07 | 1,750.00 |
| ITRON INC | Maintenance for Handheld Radio for Customer Service Retail | APR-08 | 4/08 | 112,695.72 |
| ITRON INC | Maintenance for Handheld Radio for Customer Service Retail | APR-08 | 5/08-7/08 | - |
| ITRON INC | Maintenance for Handheld Radio Software for Customer Service Retail | APR-08 | 4/08-3/09 | 5,200.00 |
| KENTUCKY STATE TREASURER | Sales Tax for Oracle Software Updates | MAY-07 | 5/07 | 32,503.47 |
| KENTUCKY STATE TREASURER | Sales Tax for Software | JUL-07 | 7/07 | 219.08 |
| LANDMARK GRAPHICS CORPORATION | Maintenance for Geographical Model Software | MAR-07 | 11/06-10/07 | - |
| LATUSPOINT INC | Maintenance for Disk Encryption Software | DEC-07 | 1/08-12/08 | 4,703.33 |
| LATUSPOINT INC | Maintenance for Disk Encryption Software | JAN-07 | 1/07-12/07 | 0.00 |
| LEVI RAY AND SHOUP INC | Maintenance for Mainframe Software | JAN-07 | 2/07-1/08 | - |
| LEVI RAY AND SHOUP INC | Maintenance for Mainframe Software | JAN-08 | 1/08-12/08 | 1,454.52 |
| LIGHTRIVER TECHNOLOGIES INC | Maintenance on VitalSuite Systems and Application Monitoring Software | JAN-08 | 1/08 | 10,875.14 |
| LIGHTRIVER TECHNOLOGIES INC | Maintenance on VitalSuite Systems and Application Monitoring Software | JAN-08 | 1/08-12/08 | 11,363.47 |
| LIVEDATA INC | Maintenance for Inter-Control Communications Protocol Software for Outage Management System | DEC-06 | 12/06-11/07 | - |
| LOGICACMG INC | Maintenance for reporting tool for Work Management System | FEB-07 | 2/07-1/08 | - |
| LOGICACMG INC | Maintenance on the Work Management System Software | FEB-07 | 2/07-1/08 | - |
| LOGICACMG INC | Maintenance on the Work Management System Software | FEB-08 | 2/08-1/09 | 54,250.00 |
| LOUISVILLE AND JEFFERSON COUNTY METROPOLITAN | License Fee for Mapping Application from Louisville and Jefferson County | DEC-07 | 12/07-11/08 | 32,272.83 |
| LOUISVILLE AND JEFFERSON COUNTY METROPOLITAN | License Fee for Mapping Application from Louisville and Jefferson County | OCT-06 | 10/06-9/07 | - |
| LUCENT TECHNOLOGIES INC | Support and Subscription for QIP & SNMP for Data Networks | JAN-07 | 1/07-12/07 | - |
| LUCENT TECHNOLOGIES INC | Support and Subscription for QIP & SNMP for Data Networks | JAN-08 | 1/08-12/08 | 3,414.14 |
| MAPFRAME CORP | Maintenance for Smallworld Geospatial Information System Mobile Application | DEC-07 | 12/07-11/08 | 19,542.08 |

**Current Test Year Annual Cost for IT Contracts**

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| MAXIMUS | Maintenance for Transportation Management Software | NOV-06 | 08/06-07/07 | - |
| MAXIMUS | Maintenance for Transportation Management Software | SEP-07 | 9/07-8/08 | 15,833.33 |
| METEORLOGIX LLC | Maintenance for Weather Software | JUL-06 | 7/06-6/07 | - |
| METEORLOGIX LLC | Maintenance for Weather Software | JUL-07 | 7/07-6/08 | 3,978.81 |
| METRETEK INC | Maintenance for Gas Monitoring Software | DEC-06 | 1/07-12/07 | - |
| MICROSOFT CORP | Microsoft Premier Support | FEB-07 | 2/07-1/08 | - |
| MICROSOFT CORP | Microsoft Premier Support | MAR-08 | 3/08-2/09 | 9,082.95 |
| MICROSOFT LICENSING GP | Microsoft Enterprise Agreement | MAY-07 | 5/07-3/08 | 613,482.84 |
| MIR3 INC | Maintenance for Software that provides alerts from Network Mgmt Systems | SEP-07 | 9/07 | 1,600.00 |
| MRO SOFTWARE INC | Maintenance for Work Management System Software | MAR-07 | 3/07-2/08 | - |
| MSI SYSTEMS INTEGRATORS | Consulting services for Database Upgrade | AUG-06 | 7/06-6/07 | - |
| MSI SYSTEMS INTEGRATORS | Consulting services for Database Upgrade | AUG-06 | 8/06-7/07 | - |
| NAVIGANT CONSULTING INC | Maintenance for Departmental Application Developer Software | DEC-06 | 12/06-11/07 | - |
| NAVIGANT CONSULTING INC | Maintenance for Departmental Application Developer Software | NOV-07 | 12/07-11/08 | 1,100.00 |
| NET IQ CORP | Maintenance for Security and Incident Management Software | DEC-06 | 12/06-11/07 | - |
| NET IQ CORP | Maintenance for Security and Incident Management Software | DEC-07 | 12/07-11/08 | 3,674.83 |
| NETEC INTERNATIONAL INC | Maintenance for Mainframe Software | APR-07 | 12/06-11/07 | - |
| NETEC INTERNATIONAL INC | Maintenance for Mainframe Software | NOV-07 | 11/07-10/08 | 1,850.00 |
| NEW AGE TECHNOLOGIES INC | Maintenance for Software that Manages VMWare Host Servers | MAY-07 | 5/07 | 11,957.89 |
| NEW AGE TECHNOLOGIES INC | Maintenance for Software that Manages VMWare Host Servers | NOV-06 | 11/06-10/07 | - |
| NEWERA SOFTWARE INC | Maintenance for Mainframe Software | NOV-06 | 12/06-11/07 | - |
| NOETIX CORP | Maintenance for Financial Reporting for Oracle | FEB-07 | 2/07-1/08 | - |
| NOETIX CORP | Maintenance for Financial Reporting for Oracle | MAR-08 | 3/08-2/09 | 2,831.46 |
| OPEN SOFTWARE TECHNOLOGIES INC | Maintenance for Mainframe Software | DEC-06 | 12/06-11/07 | - |
| ORACLE USA INC | Maintenance for Oracle Application and Database Software | MAY-06 | 6/06-5/07 | - |
| ORACLE USA INC | Maintenance for Oracle Application and Database Software | MAY-07 | 6/07-5/08 | 748,958.05 |
| ORACLE USA INC | Maintenance for Oracle Database Software | MAR-08 | 3/08 | 8,079.79 |
| ORACLE USA INC | Maintenance for Outage Management Software | JAN-08 | 1/08-12/08 | 45,129.80 |
| ORACLE USA INC | Maintenance for Peoplesoft Software | AUG-07 | 8/07-7/08 | 106,755.29 |
| ORACLE USA INC | Maintenance for Peoplesoft Software | JUL-06 | 8/06-7/07 | - |
| ORACLE USA INC | Maintenance for Peoplesoft Software | JUN-07 | 6/07 | 25,979.49 |
| ORACLE USA INC | Maintenance for Peoplesoft Software | MAR-07 | 4/07-3/08 | - |
| ORACLE USA INC | Maintenance for Peoplesoft Software | MAR-08 | 3/08-2/09 | 5,298.56 |
| ORACLE USA INC | Maintenance for Siebel products for the Customer Information System overlay | JAN-07 | 1/07-12/07 | - |
| ORACLE USA INC | Maintenance for Siebel products for the Customer Information System overlay | JAN-08 | 1/08-12/08 | 58,889.24 |
| ORACLE USA INC | Maintenance for Software to support Peoplesoft (Microfocus) | MAY-07 | 5/07 | 5,500.00 |
| ORASI SOFTWARE INC | Maintenance for Development Tool Software | JUN-06 | 6/06-5/07 | - |
| ORASI SOFTWARE INC | Maintenance for Development Tool Software | MAY-07 | 5/07-4/08 | 3,150.00 |
| PLATTS | Subscription for Energy Marketing | JAN-07 | 3/07-5/07 | - |
| PLATTS | Subscription for Energy Marketing | JAN-08 | 3/08-5/08 | 4,371.21 |
| PLATTS | Subscription for Energy Marketing | JUL-07 | 9/07-11/07 | 14,546.00 |
| PLATTS | Subscription for Energy Marketing | MAY-07 | 6/07-8/07 | 14,546.00 |

Current Test Year Annual Cost for IT Contracts

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| PLEXOS INTERNATIONAL LLC | Maintenance for Software that measures the risk of Gas | AUG-06 | 7/06-6/07 | - |
| PLEXOS INTERNATIONAL LLC | Maintenance for Software that measures the risk of Gas | SEP-07 | 9/07-8/08 | 14,420.00 |
| PLIXER INTERNATIONAL INC | Maintenance for Software for Network Troubleshooting | AUG-07 | 8/07 | 1,995.00 |
| PRINCETON SOFTECH INC | Maintenance for Mainframe Software | JAN-07 | 1/07-12/07 | 0.00 |
| PRODUCT SUPPORT SOLUTIONS INC | Maintenance for Call Center Interactive Voice Response System | APR-08 | 4/08 | 13,491.50 |
| PRODUCT SUPPORT SOLUTIONS INC | Maintenance for Call Center Interactive Voice Response System | FEB-08 | 2/08 | 13,491.50 |
| PROSYS INFORMATION SYSTEMS INC | Maintenance for Network Attached Storage Devices | DEC-07 | 12/07-11/08 | 18,426.87 |
| PROSYS INFORMATION SYSTEMS INC | Maintenance for Trend Micro Internet Security Software | JAN-08 | 1/08 | 9,333.39 |
| QUEST SOFTWARE INC | Maintenance for Development Tool Software | AUG-07 | 9/07-8/08 | (666.67) |
| QUEST SOFTWARE INC | Maintenance for Development Tool Software | OCT-06 | 9/06-8/07 | - |
| QUEST SOFTWARE INC | Maintenance for Development Tool Software | OCT-07 | 10/07 | 5,460.01 |
| RADIO SATELLITE INTEGRATORS INC | Maintenance for AVL Software | DEC-06 | 12/06-11/07 | - |
| RADIO SATELLITE INTEGRATORS INC | Maintenance for AVL Software | DEC-07 | 12/07-11/08 | 8,125.00 |
| RAXCO SOFTWARE INC | Maintenance for Defrag Software | AUG-07 | 9/07-8/08 | (4,130.00) |
| RED HAT INC | Subscription for Operating System for Server | AUG-06 | 8/06-7/09 | (38,902.15) |
| RED HAT INC | Subscription for Operating System for Server | JUN-07 | 5/07-7/08 | 29,821.44 |
| RESEARCH IN MOTION CORP | Maintenance for Blackberry Phones | SEP-07 | 9/07 | 233.58 |
| RESEARCH IN MOTION CORP | Maintenance for Blackberry Phones | SEP-07 | 9/07-8/08 | 4,370.95 |
| RJR INNOVATIONS INC | Maintenance for Service Desk Software | APR-08 | 4/08-3/09 | 3,152.63 |
| SANDSTORM ENTERPRISES INC | Maintenance for Software used to scan our Analog Lines and used by IT Security | SEP-07 | 9/07 | 560.00 |
| SECURE COMPUTING CORP | Maintenance for e-mail filtering hardware | DEC-07 | 12/07-11/08 | 7,200.90 |
| SECURE COMPUTING CORP | Subsciption for Antivirus Software | DEC-07 | 12/07-11/08 | 6,851.58 |
| SERENA SOFTWARE INC | Maintenance for Source Management Software | DEC-07 | 12/07-11/08 | 8,346.83 |
| SERENA SOFTWARE INC | Maintenance for Source Management Software | OCT-06 | 11/06-10/07 | - |
| SERENA SOFTWARE INC | Maintenance for Source Management Software | OCT-07 | 10/07 | 9,891.00 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | APR-07 | 4/07-3/08 | 0.00 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | AUG-07 | 8/07 | 7,249.94 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | FEB-07 | 2/07-1/08 | - |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | JAN-08 | 1/08-12/08 | 21,271.76 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | JUL-07 | 7/07 | 7,249.94 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | JUN-07 | 6/07 | 7,249.94 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | MAR-07 | 3/07-2/08 | 0.00 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | MAY-07 | 5/07 | 14,499.88 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | NOV-07 | 11/07-10/08 | 2,279.47 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | OCT-07 | 10/07 | 7,249.94 |
| SERVICESOURCE INTERNATIONAL LLC | Maintenance for Backup Equipment | SEP-07 | 9/07 | 7,249.94 |
| SKILLSOFT CORPORATION | Maintenance for Software for online training | JAN-07 | 1/07-12/07 | 0.00 |
| SKILLSOFT TELESALES US | Maintenance for Software for online training | DEC-07 | 12/07-11/08 | 4,382.92 |
| SOFTBASE SYSTEMS INC | Maintenance for Mainframe Database Software | DEC-06 | 12/06-11/07 | - |
| SOFTWARE ENGINEERING OF AMERICA | Maintenance for Mainframe Software | DEC-06 | 12/06-11/07 | - |
| SOFTWARE ENGINEERING OF AMERICA | Maintenance for Mainframe Software | NOV-07 | 12/07-11/08 | 2,083.33 |
| SOFTWARE HOUSE INTERNATIONAL INC | Maintenance for Backup Software | JUL-07 | 7/07 | 11,753.00 |

**Current Test Year Annual Cost for IT Contracts**

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| SOFTWARE HOUSE INTERNATIONAL INC | Maintenance for Backup Software | SEP-07 | 9/07 | 794.06 |
| SOFTWARE HOUSE INTERNATIONAL INC | Maintenance for Software used by IT Security | SEP-07 | 9/07 | 445.00 |
| SOFTWARE HOUSE INTERNATIONAL INC | Software used to learn German | JUL-07 | 7/07 | 315.00 |
| SOFTWARE INFORMATION SYSTEMS | Maintenance for AS/400 Software | JUN-06 | 6/06-5/07 | - |
| SOFTWARE INFORMATION SYSTEMS LLC | Maintenance for AS/400 Software | JUL-07 | 7/07 | 1,357.48 |
| SPATIAL BUSINESS SYSTEMS INC | Maintenance for GIS/CAD Translation Software | SEP-07 | 9/07-5/08 | 7,520.00 |
| SPI DYNAMICS INC | Maintenance for Security Software | DEC-06 | 12/06-11/07 | - |
| SPL WORLDGROUP INC | Maintenance for Outage Management Software | JAN-07 | 1/07-12/07 | - |
| STARQUEST VENTURES INC | Maintenance for Software for Customer Information System | DEC-06 | 12/06-11/07 | - |
| STARQUEST VENTURES INC | Maintenance for Software for Customer Information System | DEC-07 | 12/07-11/08 | 2,083.33 |
| STERLING COMMERCE INC | Maintenance for EDI transaction software | JAN-07 | 1/07-12/07 | - |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | APR-08 | 4/08 | 11,900.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | AUG-07 | 8/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | DEC-07 | 12/07 | 11,900.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | FEB-08 | 2/08 | 11,900.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | JAN-08 | 1/08 | 11,900.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | JUL-07 | 7/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | JUN-07 | 6/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | MAR-08 | 3/08 | 11,900.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | MAY-07 | 5/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | NOV-07 | 11/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | OCT-07 | 10/07 | 17,500.00 |
| STRUCTURE GROUP LLC | Maintenance for Energy Marketing Software | SEP-07 | 9/07 | 17,500.00 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | AUG-07 | 8/07 | 3,484.50 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | JUL-07 | 7/07 | 3,484.50 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | JUN-07 | 6/07 | 3,484.50 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | MAY-07 | 5/07 | 3,484.50 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | OCT-07 | 10/07 | 193.50 |
| SUN MICROSYSTEMS INC | Maintenance for Backup Equipment | SEP-07 | 9/07 | 3,484.50 |
| SUNGARD ENERGY SYSTEMS INC | Maintenance for Fuelworx and Budgetworx Software for Energy Marketing | FEB-08 | 2/08-1/09 | 21,514.50 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | APR-08 | 5/08 | - |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | AUG-07 | 8/07 | 59,037.00 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | DEC-07 | 1/08-12/08 | 6,026.36 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | FEB-07 | 2/07-8/07 | - |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | FEB-08 | 2/08 | 18,079.09 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | JAN-08 | 1/08 | 8,426.55 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | MAR-07 | 3/07-6/07 | - |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | MAR-08 | 4/08 | 18,079.09 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | MAY-07 | 5/07-7/07 | 22,239.00 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | MAY-07 | 5/07-7/07 | 22,239.00 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | NOV-07 | 11/07 | 19,679.00 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | OCT-07 | 10/07 | 19,679.00 |

**Current Test Year Annual Cost for IT Contracts**

| Vendor Name | Description | Period Paid | Duration | Annual Cost |
|---|---|---|---|---|
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | SEP-07 | 10/07 | 19,679.00 |
| SUNGARD RECOVERY SERVICES INC | Disaster Recovery Site Fee | FEB-8 | 2/08 | 9,652.54 |
| SURFCONTROL | Maintenance for Bluecoat Appliances and Software for Security | DEC-06 | 1/07-12/07 | - |
| SYCLO LLC | Maintenance for Software for the Work Management System | OCT-06 | 10/06-9/07 | - |
| SYMANTEC CORP | Maintenance for Backup Software | DEC-07 | DEC-2007 | 9,170.46 |
| SYMANTEC CORP | Maintenance for Backup Software | NOV-07 | 11/07-10/08 | 41,059.78 |
| TOTAL RESOURCE MANAGEMENT INC | Maintenance for Safety Tagging System Software | MAR-07 | 3/07-12/07 | - |
| TOTAL SOLUTION INC | Maintenance for Base Software Scoring for Customer Information System | DEC-06 | 12/06-11/07 | - |
| TOTAL SOLUTION INC | Maintenance for Base Software Scoring for Customer Information System | DEC-07 | 12/07-11/08 | 10,000.00 |
| VANGUARD INTEGRITY PROFESSIONALS | Maintenance on Mainframe Software | JUN-06 | 6/06-5/07 | - |
| VANGUARD INTEGRITY PROFESSIONALS | Maintenance on Mainframe Software | JUN-07 | 6/07-5/08 | 13,329.25 |
| VERAMARK TECHNOLOGIES INC | Maintenance for Telemanagement Software for the Phones | MAR-07 | 3/07-2/08 | - |
| VERISIGN INC | Subscription for Digital Certificates | AUG-07 | 8/07 | 10,240.00 |
| VERISIGN INC | Subscription for Digital Certificates | JUN-06 | 6/06-5/07 | - |
| VERITAS SOFTWARE CORP | Maintenance for Backup Software | OCT-06 | 11/06-10/07 | - |
| VMWARE INC | Maintenance for VM Infrastructure Software | AUG-06 | 8/06-7/07 | - |
| WEBTRENDS INC | Maintenance for Reporting Software | FEB-07 | 11/06-10/07 | - |
| WEBTRENDS INC | Maintenance for Reporting Software | OCT-07 | 10/07 | 2,800.00 |
| WORLD WIDE TECHNOLOGY INC | Maintenance for Security Server Software | JUL-07 | 7/07-6/08 | 158,311.01 |
| WORLD WIDE TECHNOLOGY INC | Maintenance on Cisco Equipment | AUG-06 | 8/06-7/07 | - |
| XEROX GLOBAL SERVICES INC | Maintenance for Sun Servers | JUL-06 | 7/06-6/07 | - |
| Grand Total | | | | $ 4,636,059.17 |

| | |
|---|---|
| Add Back August 2007 IT Correction | 2,479,889.24 (1) |
| Total Actual Expenses Excluding the IT Adjustment | $ 7,115,948.41 |
| Current annual cost included above | 4,636,059.17 |
| LG&E allocation | 47.99% |
| IT contract allocation of expense to LG&E | $ 2,224,837.38 |

(1) This amount is the total IT adjustment 47.98984% ($1,190,095) is allocated to LG&E as shown in Reference Schedule 1.29.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 34**

**Responding Witness: Shannon L. Charnas**

Q-34. Refer to pages 8 and 11 of the Charnas Testimony and Reference Schedule 1.31 of Exhibit 1 to the Rives Testimony. Provide the source and derivation of the 61.91 percent ratio shown on Line 6 of the reference schedule as the portion of the increased "vehicle fuel cost applicable to O & M."

A-34. The actual expenses for the vehicle costs during the test year were charged 38.09% to balance sheet accounts and 61.91% to operating and maintenance expense accounts. This is based on the actual allocation of LG&E fleet vehicle costs per the general ledger for the test year.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 35

Responding Witness: William Steven Seelye

Q-35. Refer to Volume 4 of 5 of LG&E's application, the Testimony of Lonnie E. Bellar ("Bellar Testimony"), at pages 4-7. The pro forma electric class rates of return reflect that the rate of return for Special Contracts is slightly lower than the rate of return for Residential Rate RS. Given that, unlike its gas operations, there is no threat of physical bypass by its electric customers, explain why none of LG&E's proposed increase in electric revenues is allocated to Special Contracts.

A-35. The special contract customers with a lower rate of return than the overall rate of return have contracts with terms and conditions that do not allow LG&E to propose an increase greater than the rate schedule under which the customer would otherwise take service. Because these customers would otherwise take service under either LP-TOD or LC-TOD and because LG&E is not proposing an increase to LP-TOD or LC-TOD, in accordance with the contracts, the Company cannot request an increase to the special contract customers.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 36**

**Responding Witness: William Steven Seelye**

Q-36. Refer to Volume 4 of 5 of LG&E's application at page 7 of the Bellar Testimony. Mr. Bellar states that LG&E decided to follow the cost-of-service study ("COSS") for its gas customers more closely than it did for the electric customers. Explain further why LG&E chose to follow the COSS more closely for gas customers than for electric customers.

A-36. Because of the relatively higher level of LG&E's gas customer charges compared to the electric customer charges, the Company has concluded that it can bring its gas customer charges more in line with the cost of providing service than its electric customer charges. LG&E's electric customer charges are much lower relative to the actual cost of providing service, which would result in a significant electric rate impact if the cost of service were followed more closely. In developing its proposed electric rates, the Company decided not to decrease its residential energy charges in order to bring the customer charge more closely in line with cost of service.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 37**

**Responding Witness: J. Clay Murphy**

Q-37. Refer to Volume 4 of 5 of LG&E's application, the Testimony of J. Clay Murphy ("Murphy Testimony"), at pages 4-6, which deals with the issue of declining residential gas consumption. Lines 10-16 reflect the amount of decline, from its last rate case to the current rate case, in the temperature normalized average annual consumption of LG&E's residential gas customers. Provide, on an annual basis, the temperature normalized average of LG&E's residential gas customers for the calendar years 2003 through 2007.

A-37. LG&E estimates average annual normalized residential natural gas consumption for the requested calendar years as follows:

| | |
|---|---|
| 2003 | 83.6 |
| 2004 | 81.6 |
| 2005 | 75.4 |
| 2006 | 68.1 |
| 2007 | 72.8 |

In order to produce consistent normalized results over the 5-year period from 2003 to 2007, the normalization methodology used in these calculations relies upon the 30-year normal heating degree days developed by the National Oceanic and Atmospheric Administration for the 30 years ended December 2000 for each of the 5 calendar years.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 38**

**Responding Witness: J. Clay Murphy**

Q-38. Refer to page 9 of the Murphy Testimony. Mr. Murphy states that LG&E is proposing to modify rate schedule FT to require the customer electing service under this rate schedule to provide notice to LG&E no later than March 31 and to execute a contract for service by April 30 in order to begin receiving service by the following November 1. For clarification, is this requirement for the first time a customer elects this rate schedule or must the customer notify LG&E by March 31 each year in order to be served under this rate schedule?

A-38. The March 31 notice requirement applies to the first time that the customer elects service under Rate Schedule FT. An existing customer served under Rate FT is not required to annually re-elect service under Rate FT.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 39**

**Responding Witness: J. Clay Murphy**

Q-39. Refer to page 10 of the Murphy Testimony. Referring to Rider RBS, Mr. Murphy states that this service provides firm balancing up to a stated amount of the daily mismatches between volumes delivered and volume used by the customer. LG&E is proposing to withdraw this rider because no customers have used it since 2000. Explain how the mismatch is handled if not under this rider.

A-39. Rider RBS is a service under which a customer served under Rate FT may elect a specified volume of daily firm balancing service to cover daily mismatches ("imbalances") between the volume of natural gas delivered by the customer to LG&E and the volume of natural gas used by the customer at its facility.

Absent any service under Rider RBS, mismatches between volumes delivered and volumes used by a customer are handled on an "as-available" basis through the balancing service incorporated in Rate Schedule FT.

This "as-available" daily balancing service is provided pursuant to the provisions and charges described in Rate Schedule FT. There is no charge for balancing within the +/- 10% daily imbalance tolerance set forth in Rate Schedule FT. Outside the +/- 10% daily imbalance tolerance, LG&E assesses the Utilization Charge for Daily Imbalances ("UCDI").

"As-available" daily balancing service is suspended when an Operational Flow Order ("OFO") is in effect. When an OFO is in effect, the daily imbalance tolerance is reduced from +/- 10% to +/- 0%. An OFO charge is assessed on the mismatch between the volume of natural gas delivered by the customer to LG&E and the volume of natural gas used by the customer at its facility in violation of the particular OFO directive as described in Rate Schedule FT.

As a part of its on-going re-evaluation of its gas tariffs (as further discussed in LG&E response to AG-1 Question No. 110), Rider RBS was identified for deletion since it no longer appears of interest to customers.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 40**

**Responding Witness: J. Clay Murphy**

Q-40. Refer to page 12 of the Murphy Testimony.

a. Mr. Murphy discusses the new Distributed Generation Gas Service rate that LG&E is proposing. Under what rate schedules are these customers currently being served?

b. Have any customers objected to the change?

A-40. a. All non-residential gas sales customers are served under one of three rate schedules: Rate CGS, IGS, and AAGS. Any customer with distributed generation or similar facilities that would otherwise qualify for service under Rate DGGS are receiving sales service pursuant to one of these three rate schedules.

b. LG&E is not aware of any objections raised by customers to this new rate schedule. At this time, LG&E is not proposing to require existing customers with small gas-fired distributed generation installations to take service under this new rate schedule. However, all future installations will be required to take service under this new rate schedule. LG&E reserves the right to terminate existing contractual relationships and transfer existing customers with existing distributed generation installations to this new rate schedule in the future, consistent with any notice provisions in those contracts.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 41**

**Responding Witness: Robert M. Conroy**

Q-41. Refer to the Conroy Testimony at page 4. Mr. Conroy states that LG&E and KU have not been able to completely harmonize their rate schedules. Explain in detail why the companies have been unable to do so.

A-41. The Companies have made considerable progress towards harmonizing the terms and conditions and the structure of the rate schedules between KU and LG&E. The changes that were made in the previous rate cases and those that are being proposed in this proceeding provide benefits to the administration and interpretation of the services provided to customers, and ultimately improved customer service and satisfaction. LG&E and KU have not completed the harmonize their rate schedules because the Companies believe that further changes at this time would have resulted in significant customer billing impacts and strained both metering and administrative resources. The Companies will continue to evaluate and harmonize their rate schedules in the future where appropriate.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 42**

**Responding Witness: Robert M. Conroy**

Q-42. Refer to page 6 of the Conroy Testimony. Explain why LG&E decided to eliminate the summer and winter rates in Rate GS and propose a flat rate.

A-42. LG&E decided to eliminate the GS summer/winter rate differentials and offer a flat rate for the same reasons that the residential rate differentials were eliminated in the last rate case. In approving the elimination of the LG&E residential differentials, the Commission ordered LG&E to file a report on whether the results of the rate change caused an increase in summer usage. The report found no such impact. Seasonal differentials simply are not effective in encouraging conservation absent being used in tandem with time-of-day differentials. Customers do not shift load for months at a time. In the case of GS, the elimination of the differentials is combined with restriction of the rate to a much more homogeneous customer group where the bundled rate structure can reflect cost and is now harmonized with the KU GS rate structure.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 43

Responding Witness: Butch Cockerill

Q-43. Refer to Volume 4 of 5 of the application, the Sidney L. "Butch" Cockerill Testimony ("Cockerill Testimony"), at page 2.

a. Explain more fully the nature of the Meter Pulse Charge.

b. Refer to page 2 of the Cockerill Testimony. Mr. Cockerill states that LG&E is proposing to eliminate its policy of paying for customers' meter bases.

(1) What is the current cost for a meter base?

(2) Provide the total costs incurred by KU to supply meter bases for the test year and annually for calendar year 2005, 2006, and 2007.

(3) Are all of KU's costs for meter bases capitalized or expensed?

(4) Has KU historically maintained the meter bases that it provided to customers? If yes, will KU continue to maintain those meter bases?

(5) If KU has historically maintained the meter bases that it provided, does KU intend to maintain the customer-supplied meter bases in the future?

(6) Explain why LG&E is proposing to change this policy.

A-43. a. The Meter Pulse Charge is designed to recover cost incurred by the Company for special equipment installed on the Company's metering devices to provide the customer with real time data (data pulses) allowing the customer to control its electric power demand. This service is not normally provided to customers except at their request.

Company assumes the references to "KU" were intended for LG&E.

b. (1) 125 Amp Residential Base - $17.00
200 Amp Residential Base - $24.00
320 Amp Residential Base - $105.00

(2) Test Year - $84,300
2005 - $135,000
2006 - $140,000
2007 - $150,000

(3) Capitalized.

(4) No.

(5) Not applicable.

(6) Historically the Company has furnished meter bases for customers to ensure consistency in the types of meter bases being installed in our service territory. The benefits to the company were improved operational efficiency and employee safety by achieving a standard meter base design. Over the past several years, the electrical supply manufacturers have established a standardized off-the-shelf common meter base for single phase electric meters, thus eliminating the need for the Company to continue furnishing these type meter bases. The company will continue to provide meter bases for three-phase meter bases due to the multiple types of bases and the importance of having the proper equipment to achieve the benefits stated above.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 44**

**Responding Witness: Butch Cockerill**

Q-44. Refer to page 5 of the Cockerill Testimony. Mr. Cockerill states that customers whose payments are received more than 10 days after the bills are issued will have their behavioral scores affected in the behavioral scoring system.

A-44. The Company assumes the above statement was intended to be part of Question No. 45. Please see response to Question No. 45.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 45**

**Responding Witness: Butch Cockerill**

Q-45. Explain the behavioral scoring system.

a. Identify all the ways that a customer can be affected by a negative behavioral score.

b. Explain in detail the effect of LG&E's proposed 10-day collection cycle on a customer who has no deposit with LG&E, whose historic bills have been paid within 11 to 15 days, and whose future bills are paid within 11 to 15 days.

A-45. LG&E's behavioral scoring model was introduced in September, 2005. The purpose of this model is fourfold:

- To objectively measure individual customer behavior, based solely on the customer's internal payment habits with LG&E.
- To improve customer satisfaction by sending disconnect notices to fewer customers.
- To delay the beginning of the collection process for medium risk customers, and
- To keep low risk customers out of the credit cycle entirely.

Specific customer benefits are as follows:

- Low risk customers do not receive a disconnect notice until two months in arrears.
- Medium risk customers do not receive a disconnect notice until one month in arrears.
- High risk customers receive a disconnect notice when current bill is past due (this was the practice for **all** customers prior to September, 2005).
- A customer's risk category can change over time, based on his/her payment behavior. In essence, a customer can be rewarded by improving his/her payment habits.

Each residential customer account is scored monthly, two days past the current bill due date. Six attributes are reviewed monthly, and a risk category (low, medium and high) is assigned to each customer, based on the score. The six attributes are:

- The number of times delinquent in the past eight months;

- The number of months since the customer was last eligible to be disconnected;
- The number of accounts receivable aging buckets (30, 60. 90, 90+) with a balance greater than $0;
- The total delinquent balance;
- The number of months since becoming a customer;
- The number of month's since the customer's last payment.

It is important to note, prior to the implementation of this model, all customers who were delinquent on their current bill received a disconnect notice. There were no distinguishing factors, other than this. Since behavioral modeling was implemented, fewer disconnect notices have been sent to customers. Therefore, a customer who pays late does not necessarily mean that he/she will be categorized a medium or high risk customer. If the customer is late each month, but pays his/her bill in full each month, it is unlikely he/she will receive a disconnect notice.

a. The only way a customer can be affected by a negative behavioral score is that he/she would receive a disconnect notice on a delinquent current bill only, in accordance with existing PSC regulations and LG&E tariffs. The behavioral scoring system is not designed to penalize customers, it is intended to reward improved payment history by delaying the sending of a disconnect notice until the score reaches a high enough risk factor to warrant a notice being sent.

b. There would be no affect on this customer, given this scenario. Deposits are only assessed at either the time of application for service, or following disconnect for nonpayment. As long as the customer continues to pay within 10 – 15 days, no late payment charge would be assessed, and no deposit would be assessed.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 46**

**Responding Witness: Butch Cockerill**

Q-46. Refer to page 5 of the Cockerill Testimony. Provide any studies or analyses of the impacts on revenues, uncollectibles, and cash flow of having payments due 10 days after the date of the bill, with a penalty imposed for payment after the $15^{th}$ day, versus bills due 15 days after the date of the bill, with a penalty imposed for payment after the $15^{th}$ day.

A-46. The Company has not performed any such studies.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 47

Responding Witness: Butch Cockerill

Q-47. Refer to SLC Exhibit 3 to the Cockerill Testimony. Provide the derivation of the $14.50 amount used in the calculation.

A-47. The cost for disconnecting and reconnecting a service is based on the average cost of completing all service orders during the test period. The breakdown is as follows:

| | Disconnect | Reconnect | Total |
|---|---|---|---|
| Company Labor | $ 8.43 | $ 8.43 | $ 16.85 |
| Transportation | 1.20 | 1.20 | 2.40 |
| Outside Services | 4.66 | 4.66 | 9.33 |
| Supplies and Materials | 0.21 | 0.21 | 0.41 |
| Total Costs | $ 14.50 | $ 14.50 | $ 29.00 |

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 48**

**Responding Witness: William Steven Seelye**

Q-48. Refer to Volume 5 of 5 of LG&E's application, the Testimony of William Steven Seelye ("Seelye Testimony"), at page 2, and Seelye Exhibits 25-35. Provide an electronic copy of both the electric and gas cost-of-service studies with all formulas intact.

A-48. The requested information is being provided on CD.

LOUISVILLE GAS AND ELECTRIC COMPANY

CASE NO. 2008-00252
CASE NO. 2007-00564

Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 49

Responding Witness: William Steven Seelye

Q-49. Refer to pages 6-9 of the Seelye Testimony and Seelye Exhibit 2.

a. The testimony, at page 6, indicates that, relying heavily on the results of its electric cost-of-service study, LG&E is proposing to increase rates for only the residential and lighting rate schedules. Explain why no increases are proposed for the Large Commercial Time-of-Day or Industrial Power Time-of-Day customers served at primary voltages, since, according to the cost-of-service study, the rates of return for those groups are below the total system average rate of return.

b. The testimony, at pages 8-9, indicates that LG&E's residential customer charge is too low and that its residential energy charge is too high. LG&E is proposing to increase the customer charge from $5.00 to $8.23 and make no change to the energy charge. To what extent did LG&E consider a larger increase to the residential customer charge and a decrease, of some magnitude, to the residential energy charge?

A-49. a In analyzing rate options for Rate LP-TOD, the Company concluded that it is important to maintain the current demand charge differentials between the Transmission, Primary, and Secondary voltages. It is also important to maintain the existing demand charge relationship between Rate LP and Rate LP-TOD. Over the years, the Company has attempted to maintain parity between Rate LP and Rate LP-TOD so that, unless they can shift demand to the off-peak period, customers remain economically indifferent between taking service under Rate LP and taking service under Rate LP-TOD. Therefore, in considering rate design options for these rates, the Company analyzed the rates of return for Rate LP-TOD-Transmission, Rate LP-TOD-Primary, Rate LP-TOD-Secondary, Rate LP-Primary, and Rate LP-Secondary both individually and as a group. Because the rate of return for Rate LP-Primary was reasonably close to the overall rate of return, the Company decided not to disturb the current relationships that exist between Rate LP and Rate LP-TOD and among the various voltage levels in order to bring Rate LP-TOD-Primary directly in line with the cost of service study.

b. Consideration was given to decreasing the energy charge and increasing the customer charge by an even larger amount. A higher customer charge could certainly be supported on the basis of the cost of service study and for other reasons. However, due to the likelihood that the Companies will need to file rate cases in the near future (i.e. due to the need to recover the costs associated with Trimble County Unit 2), the Company decided that it should take a more gradual or incremental approach of making adjustments to customer charges in a single rate case.

**LOUISVILLE GAS AND ELECTRIC COMPANY**

**CASE NO. 2008-00252**
**CASE NO. 2007-00564**

**Response to Second Data Request of Commission Staff**
**Dated August 27, 2008**

**Question No. 50**

**Responding Witness: William Steven Seelye**

Q-50. Refer to page 16 of the Seelye Testimony. Provide a sample bill for a transmission customer under the current KW basis billing method and a sample bill for that same customer under the proposed kVa billing method.

A-50. See attached.

Customer Service: (502) 589-1444 Mon-Fri 7AM-7PM(EST)
Walk-in Center Hours: Mon-Fri 8AM-5PM(EST)
Telephone Payments: (800) 780-9723
Power Outage Reporting: (502) 589-3500
www eon-us com

LG&E an e·on company

| DATE DUE | AMOUNT DUE |
|---|---|
| 08/26/08 | $63,754.22 |

Want to reduce the seasonal highs and lows normally ssociated with utility bills? Sign up for our Budget Payment Plan! Simply check the box on your bill stub before returing it with your next payment

## ACCOUNT INFORMATION

| | |
|---|---|
| **Account Number:** | 0000-0000-0000-00 |
| **Account Name:** | JOHN DOE |
| **Service Address:** | 1234 ANYWHERE ST |
| **Next Read Date:** | 09/08/08 |

| Averages for Billing Period | This Year | Last Year |
|---|---|---|
| Average Temperature | 81 ° | 79 ° |
| Number of Days Billed | 30 | 29 |
| Electric/kwh per day | 44800 0 | 45103 4 |

## BILLING SUMMARY

| | | |
|---|---|---|
| Previous Balance | | 76 72 |
| Summary Transfer | | (76.72) |
| Balance as of 08/08 | | 0.00 |
| Electric Charges | 63.677 50 | |
| Utility Charges as of 08/08 | | 63.677 50 |
| Other Charges | | 76.72 |
| **Total Amount Due** | | 63,754.22 |

## ELECTRIC CHARGES

| | |
|---|---|
| **Rate Type: Large Power Transmission TOD** | |
| Customer Charge | $120 00 |
| Energy Charge | $31.745 28 |
| Demand Charge ($2 63x2304 kw) | $6.059 52 |
| Peak Demand Charge ($9 28 x 2160kw) | $20.044 80 |
| Power Factor Charge 72% (0 048 x $26.104 32) | $1.253 01 |
| **Other Charges For Above Rates** | |
| Electric Fuel Adjustment ($ 00355 x 1344000 kwh) | $4.771 20 |
| Environmental Surcharge (1 020% x $63.993 81) | $652 74 |
| 'lerger Surcredit (1 499% CR x $64.646 55) | -$969.05 |
| **Total Electric Charges** | $63,677 50 |

Please see reverse side for additional charges.

Bring entire bill when paying in person.

**Customer Service (502) 589-1444**

**PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

| Account Number |
|---|
| 0000-0000-0000-00 |

| Payment Due Date | Amount Due by Due Date | Amount Due 5 Days After Due Date | Winter Help Donation | Amount Enclosed |
|---|---|---|---|---|
| 08/26/08 | $63,754.22 | $63,754.22 | $ | $****** |

Home Phone # (502) 123-4567

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY: MB
C14, R0067, G999999
P62 45

LG&E

P.O Box 537108
ATLANTA. GA 30353-7108

#BWNGGLS
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JOHN DOE
1234 ANYWHERE ST
LOUISVILLE KY 40291-3667

ᴣrvice Address: 1234 ANYWHERE ST

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**Attachment to Response to PSC-2 Question No. 50**

**Page 1 of 2**

**Seelye**

Exhibit A-50 1

Sample: LGE Transmission Customer current kW bill

Customer Service: (502) 589-1444 Mon-Fri 7AM-7PM(EST)
Walk-in Center Hours: Mon-Fri 8AM-5PM(EST)
Telephone Payments: (800) 780-9723
Power Outage Reporting: (502) 589-3500
www.eon-us.com

an e·on company

| DATE DUE | AMOUNT DUE |
|---|---|
| 08/26/08 | $68,500.51 |

'Vant to reduce the seasonal highs and lows normally ssociated with utility bills? Sign up for our Budget Payment Plan! Simply check the box on your bill stub before returing it with your next payment

## ACCOUNT INFORMATION

| | |
|---|---|
| **Account Number:** | 0000-0000-0000-00 |
| **Account Name:** | JOHN DOE |
| **Service Address:** | 1234 ANYWHERE ST |
| **Next Read Date:** | 09/08/08 |

| Averages for Billing Period | This Year | Last Year |
|---|---|---|
| Average Temperature | 81 ° | 79 ° |
| Number of Days Billed | 30 | 29 |
| Electric/kwh per day | 44800.0 | 45103.4 |

## BILLING SUMMARY

| | | |
|---|---|---|
| Previous Balance | | 76 72 |
| Summary Transfer | | (76.72) |
| Balance as of 08/08 | | 0.00 |
| Electric Charges | 68.423 79 | |
| Utility Charges as of 08/08 | | 68.423 79 |
| Other Charges | | 76.72 |
| **Total Amount Due** | | 68,500.51 |

## ELECTRIC CHARGES

| | |
|---|---|
| **Rate Type: Retail Transmission Service** | |
| Customer Charge | $120 00 |
| Energy Charge | $31,745 28 |
| Demand Charge ($2 29 x 3293 kva) | $7.540 97 |
| Peak Demand Charge ($8 08 x 2920 kva) | $23.593 60 |
| **Other Charges For Above Rates** | |
| Electric Fuel Adjustment ($ 00355 x 1344000 kwh) | $4,771 20 |
| ıvironmental Surcharge (1 020% x $63.993 81) | $652 74 |
| **Total Electric Charges** | **$68,423 79** |

Please see reverse side for additional charges.

Bring entire bill when paying in person.

**Customer Service (502) 589-1444**

**PLEASE RETURN THIS PORTION WITH YOUR PAYMENT**

| Account Number |
|---|
| 0000-0000-0000-00 |

| Payment Due Date | Amount Due by Due Date | Amount Due 5 Days After Due Date | Winter Help Donation | Amount Enclosed |
|---|---|---|---|---|
| **08/26/08** | **$68,500.51** | **$69,185.52** | **$** | **$******** |

Home Phone # (502) 123-4567

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY: MB
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P62 45

**#BWNGGLS**
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**JOHN DOE**
**1234 ANYWHERE ST**
**LOUISVILLE KY 40291-3667**

P O. Box 537108
ATLANTA. GA 30353-7108

Service Address: 1234 ANYWHERE ST

**Attachment to Response to PSC-2 Question No. 50**

**Page 2 of 2**

**Seelye**

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Exhibit A-50.1

Sample: LGE Transmission Customer Proposed kVA bill