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PUBLIC SERVICE COMMISSION

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

Kentucky Utilities 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

September 11, 2008

RE: ***Application of Kentucky Utilities Company for an Adjustment of Base Rates*** **– Case No. 2008-00251**

Application of Kentucky Utilities Company to File Depreciation Study **– Case No. 2007-00565**

Dear Ms. Stumbo:

Please find enclosed and accept for filing the original and ten (10) copies of the Response of Kentucky Utilities 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. 100(b)(2)-(5), 102(b), (c), (d), (e)(1), (f)(1), 115(a)-(b), 118(b), 128, and 129.

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

Counsel of Record

Allyson K. Sturgeon, Senior Corporate Attorney – E.ON U.S. LLC
Robert M. Watt – Stoll Keenon Ogden PLLC (Kentucky Utilities)
Kendrick R. Riggs – Stoll Keenon Ogden PLLC (Kentucky Utilities)
W. Duncan Crosby – Stoll Keenon Ogden PLLC (Kentucky Utilities)
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)
David C. Brown – Stites and Harbison (Kroger)
Willis L. Wilson – LFUCG Department of Law (LFUCG)
Joe F. Childers (CAK and CAC)

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 KENTUCKY UTILITIES COMPANY FOR AN ADJUSTMENT OF BASE RATES	)))	CASE NO. 2008-00251
APPLICATION OF KENTUCKY UTILITIES COMPANY TO FILE DEPRECIATION STUDY	)))	CASE NO. 2007-00565

RESPONSE OF
KENTUCKY UTILITIES 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 Kentucky Utilities 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. Ely (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 Kentucky Utilities 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 Kentucky Utilities 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, Ph.D.

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

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 Kentucky Utilities 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.

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.

(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 Kentucky Utilities 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 Kentucky Utilities 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. Ely (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 Kentucky Utilities 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. Ely (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 Kentucky Utilities 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 Kentucky Utilities 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

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. 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.

W. Seelye

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.

Tammy J. Elzy (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

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 1

Responding Witness: Robert M. Conroy / Butch Cockerill / William Steven Seelye

Q-1. Refer to Volume 1 of 5 of KU's Application, 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.

c. Explain why the late penalty for rates PS, TOD, LTOD, RTS, and IS is 1 percent rather than 5 percent.

d. Refer to proposed P.S.C. No. 14, Original Sheet No. 10. Under "Availability of Service" it is stated that "[e]xisting customers with an average maximum load exceeding 50kW who are receiving service under P.S.C. 13, Fourth Revision of Original Sheet No. 10 as of September 1, 2008, will continue to be served under this rate at their option." Clarify whether September 1, 2008 is to be the cut-off irrespective of when the Commission issues a final order in this case or if KU included that date merely because it was the proposed effective date of the tariff.

e. Refer to Fourth Revision of Original Sheet No. 10 and Original Sheet No. 10.1. Under "Availability of Service" KU deleted the following language: "It is optional with the customer whether service will be billed under this schedule or any other schedule applicable to this load. Customer executing a one year contract under this schedule will continue to be billed under such schedule for not less than 12 consecutive months unless there shall be a material and permanent change in this customer's use of service." Service under this schedule is currently limited to maximum loads not exceeding 500 kW, and service to existing customers with a maximum load exceeding 500 kW is restricted to those customers being billed under the rate schedule as of its effective date of July 1, 2004. KU is proposing to limit this rate to average maximum loads not exceeding 50 kW.

(1) Provide a copy of any and all information or notification being provided to each customer that is currently receiving service for loads between 50 kW and 500 kW regarding this change.

(2) Provide the cost impact for customers receiving service for loads between the 50 kW and 500 kW who will be affected by this change.

(3) KU deleted the "Primary Discount paragraph." Explain why it is appropriate to delete the primary discount for customers who opt to continue to be served under this rate.

f. Refer to proposed P.S.C. No. 14, Original Sheet No. 12 and Volume 4 of 5 of KU's application, the Testimony of Robert M. Conroy ("Conroy Testimony") at page 7. KU is proposing to restrict service under this rate to those customers receiving service as of the effective date when this schedule was approved by the Commission.

(1) Explain why KU is proposing to restrict the All Electric School ("AES") rate to those customers receiving service as of the effective date of Commission approval.

(2) If ownership of the account changes but service provided by the utility remains the same, will the new owner have the same service classification?

g. Refer to proposed P.S.C. No. 14, Original Sheet No. 15. Under "Availability of Service," KU states that customers receiving service under this rate as of September 1, 2008 with loads not meeting the specified criteria will continue to be served under this rate at the customer's option. KU also states that customers with loads not meeting the specified criteria who initiate service after September 1, 2008 will be billed at the appropriate rate. Clarify whether September 1, 2008 is to be the cut-off irrespective of when the Commission issues a final Order in this case or if KU included that date merely because it was the proposed effective date of the tariff.

h. Refer to proposed P.S.C. 14, Original Sheet 20. Explain why the termination notice is being changed from 30 days to 90 days.

i. Refer to proposed P.S.C. No. 14, Original Sheet No. 25 and page 12 of the Conroy Testimony. State how the On-peak and Off-Peak demand charges were calculated.

j. Refer to proposed P.S.C. No. 14, Original Sheet No. 30.

(1) The term "large industrial time-of-day is used twice under "Availability of Service." Given the change in the title of this schedule, did KU intend to change the "large industrial time-of-day" terminology in the text?

(2) This schedule includes a transmission service rate. Explain why KU is proposing to provide transmission service under this rate while all other transmission service

will be provided under the new Retail Transmission Service ("RTS") rate and explain why the transmission service rates differ.

k. Refer to proposed P.S.C. 14, Original Sheet 36.4. Explain why notification was changed from 48 hours to two business days.

l. Refer to proposed P.S.C. No. 14, Original Sheet No. 37 and No. 38 and Volume 4 of 5 of KU's application at pages 13-14 of the Conroy Testimony. KU is proposing a new Lighting Energy Service ("LE") rate and a Traffic Energy Service ("TE") rate. Under what current rate schedule(s) are customers charged who will be eligible for the proposed LE and TE rates?

m. Refer to proposed P.S.C. No. 14, Original Sheet No. 45 and Volume 4 of 5 of KU's application, the Testimony of Sidney L. "Butch" Cockerill ("Cockerill Testimony"), at page 2. KU is proposing to implement a Meter Pulse Charge and Meter Data Processing Charge. Explain more fully the nature of the Meter Pulse Charge.

n. Refer to proposed P.S.C. 14, Original Sheet 60. Under "Leased Facilities Charge," it is stated that the "Company shall provide normal operation and maintenance of the leased facilities. Should the leased facilities suffer catastrophic failure, customer must provide for replacement or, at customer's option, terminate the agreement."

   (1) Explain why the customer must provide for replacement or, at customer's option, terminate the agreement.

   (2) If customer terminates the agreement, is there a fee charged to the customer? If yes, state the amount of the fee and how the fee is calculated.

o. Refer to proposed P.S.C. 14, Original Sheet 61. Under "Term of Contract," it is stated that the minimum contract shall be renewed for one-year periods until either party provides the other with Ninety (90) days written notice of a desire to terminate the arrangement."

   (1) Explain the impact of this added language on the current contracts.

   (2) Provide a copy of any and all information that will be provided to the current customers.

   (3) Explain the terms and conditions that will be deemed necessary when KU requests a contract be executed for a longer initial term.

p. Refer to proposed P.S.C. No. 14, Original Sheet No. 86 and No. 86.3. Given that the Demand-Side Management ("DSM") Cost Recovery Mechanism is mandatory for the Volunteer Fire Department ("VFD") Service rate as shown on P.S.C. No. 14, Original Sheet No. 86.3, explain why KU deleted references to VFD from the DSM calculations set-out in the tariff text in the last paragraph of proposed P.S.C. No. 14, Original Sheet No. 86.

q. Refer to proposed P.S.C. No. 14, Original Sheet No. 86.3. Provide the origin of the DSM energy charges shown under the "Power Service Rate PS" section on this page.

r. Refer to proposed P.S.C. No. 14, Original Sheet No. 102.1. Under "Other Service," No. 1, KU references Chapter 87 of the Kentucky Administrative Regulations. Clarify whether KU intended to reference Chapter 807 rather than Chapter 87.

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, LP, Large Power Service, 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 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.

LP, Large Power Service, and MP, Mine Power Service, are currently available to new loads up to 5,000 kW. These rates are combined in a proposed PS rate that 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. Combining the LP and MP rates is desirable because there is no cost justification for specific rates based on business type. Rates should be based on the cost determined by consumption pattern. Most importantly, rather than limit a billing structure the new parameters make 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.

TOD, Time-of-Day Service, is a new offering for loads from 250 kW to 5,000 kW. It replaces the pilot program STOD which was ineffective. Most importantly, it makes time-of-day pricing available to all customers above 250 kW. This affords the customer a greater opportunity to control the monthly billing and sends a more accurate price signal.

LCI-TOD, Large Commercial/Industrial Time-of-day Service, and LMP-TOD, Large Mine Power Time-of-Day Service, are currently available to new loads from 5,000 kW to 50,000 kW. The proposed LTOD rate, Large Time-of-Day Service, combines the current rates allowing service secondary and primary service from 5,000 kW to 50,000 kW. Transmission service would be on a new service, RTS. (See 1b) There is no change in availability based on kW or kWh.

b. Transmission service was eliminated from LP, Large Power Service, MP, Coal Mining Power Service, LCI-TOD, Large Commercial/Industrial Time-of-Day Service, and LMP-TOD, Large Mine Power Time-of-Day Service. 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.

c. The current tariffs for LG&E apply a 1% late penalty fee for large commercial and large industrial customers while applying a 5% fee for residential and general service customers. Rates PS, TOD, LTOD, RTS, and IS are the new proposed rate schedules for KU's large commercial and large industrial customers, thus to achieve harmonization with LG&E, we are proposing to apply a 1% late payment fee to these rate schedules.

d. The September 1, 2008, date referred to under AVAILBILITY OF SERVICE on the proposed P.S.C. No. 14, Original Sheet No. 10, was the proposed effective date of the tariff. It is anticipated that the actual date will be determined by the Commission's final order approving the rates in this proceeding.

e. (1) The information and notification being provided each customer currently receiving service on P.S.C. No. 13, Fourth Revision of Original Sheet No. 10, with loads of between 50 kW and 500 kW is that provided in the required newspaper notice. (See KU's Application, Tab 9).

(2) No customers currently receiving service under this rate would be affected by this change. Customers between 50 kW and 500 kW would be 'grandfathered' on the rate. They would not be moved to another applicable rate unless they requested a change and that will be following the Commission's final order in this proceeding. It is assumed such a request would be made because of a potential billing reduction.

(3) The paragraph titled PRIMARY DISCOUNT was deleted from P.S.C. No. 13, Fourth Revision of Original Sheet No. 10, because KU does not propose to continue to serve those customers on GS and they will be migrated to the proposed rate PS. (See response to 1a above)

f. (1) KU is proposing to restrict the All Electric School ("AES") rate to those customers receiving service as of the effective date of the Commission's approval because the rate has outlived its intended purpose and there is no differentiation in the electric service provided schools from other customers from a cost of service perspective. As noted previously with respect to rate GS, this is a bundled rate. AES was originally a promotional rate intended to encourage the use of electricity and contribute to the building of schools. Unfortunately, no limit was set on the size of such loads and it is now desirable to promote conservation and energy efficiency. This is best done by restricting the use of the bundled rate and requiring new customers be billed with a rate sending a clearer price signal.

(2) This rate is available for "school purposes by duly constituted school authorities of Kentucky". It is not anticipated there would a change in ownership. However, should one occur, as with any other 'grandfathered' customer on any other rate, the new owner is a new customer and would not be eligible for AES.

g. The references to the September 1, 2008, date under AVAILBILITY OF SERVICE on the proposed P.S.C. No. 14, Original Sheet No. 15, was the proposed effective date of the tariff. It is anticipated that the actual date will be determined by the Commission's final order approving the rates in this proceeding.

h. The termination notice under TERM OF CONTRACT was set at 90 days on the proposed No. 14, Original Sheet No. 20.1, to be consistent with the other time-of-day rate schedules where the termination notice is 90 days. This is also the termination notice of the proposed LTOD. It is preferable to maintain consistency between these two rates.

i. The demand charges for Rate RTS were calculated to be revenue neutral to the current demand charges for all customers served under the current rates, except that the billing determinants and demand charges are based on kVA demands rather than kW demands.

j. (1) Yes. The two references to 'large industrial time-of-day' under AVAILBILITY OF SERVICE on the proposed P.S.C. No. 14, Original Sheet No. 30, should have been changed to "industrial".

(2) Transmission service is contained along with secondary and primary on the proposed P.S.C. No. 14, Original Sheet No. 30. The reason for separating transmission service from secondary and primary on the other rate structures revolved around making changes to transmission that were not made to secondary and primary. In this case all rates are already kVA billed and it is desirable to keep the services together since they share common non-conforming characteristics. It is this non-conforming load pattern, the rapid fluctuating of load over short periods of time, that results in the charge differentials.

k. The change to two (2) business days was made to further clarify the preceding sentence stating that all service and maintenance would be performed only during regular scheduled working hours of the Company.

l. No current customers are provided the type of service proposed in P.S.C. No. 14, Original Sheet No. 37, Lighting Energy Service ("LE") or Original Sheet No. 38, Traffic Energy Service ("TE"). These rate schedules are new services offered to KU customers.

m. 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.

n. (1) The verbiage "Company shall provide normal operation and maintenance of the leased facilities. Should the leased facilities suffer catastrophic failure, customer must provide for replacement or, at customer's option, terminate the agreement" was added under LEASED FACILITY CHARGE of the proposed P.S.C. No. 14, Original Sheet No. 60 to recognize actual practice in administration of that rate. The rate allows for either KU supplying the facilities and the customer paying a rate of 1.62% or the customer paying for the facilities and paying a rate of 0.68%. When the customer elects to pay for the facilities in order to pay the lower rate, KU should not pay for replacement of the facilities. To do so would in essence charge other customers for the investment. In practice, customers have been informed when applying the Excess Facilities rider this will be the process. No such failures have occurred to date.

(2) Should the customer terminate the agreement following catastrophic failure of the leased facilities there would be no fee.

o. (1) Proposed P.S.C. No. 14, Original Sheet No. 61, renamed SPECIAL TERMS AND CONDITIONS as TERM OF CONTRACT and added language stating "and shall be renewed for one-year periods until either party provides the other with ninety (90) days written notice of a desire to terminate the arrangement." This language was added to correct a deficiency in the current tariff which failed to address how the agreement would be continued or terminated.

(2) It is not anticipated any information will be given current customers. They will continue to be served under the tariff and given the opportunity to either terminate the agreement or continue service as their five year anniversary approaches.

(3) The provision for an original contract term of greater than five years is part of both the current REDUNDANT CAPACITY RIDER and is unchanged in the proposed tariff. There would be no 'terms and conditions' beyond a greater original contract term required by an unusual expenditure by the Company to provide such service or the difficulty in providing such service.

p. VFD should not have been deleted from the proposed P.S.C. No. 14, Original Sheet No. 86. the section in question should read "The non-variable revenue requirement for the Residential, Volunteer Fire Department, and General Service customer Class is defined as the weighted average price per kWh of expected billings under the energy charges contained in the RS, VFD, and GS rate schedules in the up-coming...."

q. The proposed P.S.C. No. 14, Original Sheet No. 86.3, erroneously shows

Power Service Rate PS	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00008 per kWh
DSM Revenues from Lost Sales (DRL)	\$ 0.00006 per kWh
DSM Incentive (DSM)	\$ 0.00000 per kWh
DSM Balancing Adjustment (DBA)	\$(0.00005) per kWh
Total DSMRC for Rate PS	\$ 0.00009 per kWh

Time-of-Day Rate TOD	Energy Charge
DSM Cost Recovery Component (DCR)	\$ 0.00028 per kWh

DSM Revenues from Lost Sales (DRL)	$ 0.00008 per kWh
DSM Incentive (DSM)	$ 0.00001 per kWh
DSM Balancing Adjustment (DBA)	$ 0.00005 per kWh
Total DSMRC for Rate PS	$ 0.00042 per kWh

The correct presentation would have been

Power Service Rate PS and Time-of-Day Service TOD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00028 per kWh
DSM Revenues from Lost Sales (DRL)	$ 0.00008 per kWh
DSM Incentive (DSM)	$ 0.00001 per kWh
DSM Balancing Adjustment (DBA)	$ 0.00005 per kWh
Total DSMRC for Rates PS and TOD	$ 0.00042 per kWh

Large Time-of-Day Rate LTOD	Energy Charge
DSM Cost Recovery Component (DCR)	$ 0.00000 per kWh
DSM Revenues from Lost Sales (DRL)	$ 0.00000 per kWh
DSM Incentive (DSM)	$ 0.00000 per kWh
DSM Balancing Adjustment (DBA)	$ 0.00000 per kWh
Total DSMRC for Rate LTOD	$ 0.00000 per kWh

The origin of the corrected charges is PS and TOD are drawn from the current LP and STOD while LTOD is drawn from the current LCI-TOD .

r. The reference under OTHER SERVICE, 1), of the proposed P.S.C. No. 14, Original Sheet No. 102.1, to "Chapter 87 KAR" should have been to "Chapter 807 KAR".

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 2

Responding Witness: William Steven Seelye

Q-2. Refer to Volume 1 of 5 of KU's application, Tab 8, proposed P.S.C. No. 14, Original Sheet No. 20, and the report filed by KU on July 18, 2008 which provided its review of the Small Commercial Time-of-Day ("STOD") Rate pilot program. It appears that if the STOD tariff is cancelled, customers who meet the load requirements would be eligible to take service under the proposed Time-of-Day Service ("TOD").

a. For the TOD rate, explain why KU is proposing an on and off-peak demand charge and eliminating the on and off-peak energy charge.

b. If the proposed TOD rate had been in effect for the past 12 months, provide the effect it would have had on the bills of customers currently being billed under the STOD rate.

A-2. a. Because KU's generating resources consist predominately of coal-fired steam generating units, its average energy costs do not vary significantly by pricing period. Rate STOD was implemented as a pilot on an *experimental basis* as part of a settlement agreement with Kroger and other parties in Case No. 2003-00434, the Company's last base rate case. The Company determined that Rate STOD has not been effective in encouraging customers to shift load to the off-peak period. Furthermore, Rate STOD does not reflect the cost of providing service to these customers. The Company developed its proposed time of day demand rate to be responsive to customers' requests for time of day pricing and to send proper price signals.

b. See attached.

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2) Bills	(3) Total KWH	(4) Present Rates	(5) Calculated Revenue at Present Rates	(6) Proposed Rates	(7) Calculated Revenue at Proposed Rates
STOD-P Rate Code 582 (Customers Eligible for Service Under Rate TOD-Primary)						
Customer	24		$ 90.00	$ 2,160	$ 120.00	2,880
Demand (KW)	26,938		$ 7.26	195,573		
On-Peak Demand (KW)	26,938				$ 6.00	161,630
Off-Peak Demand (KW)	26,658				$ 1.27	33,856
Minimum Demand				-		-
On Peak Energy		7,988,094	$ 0.03879	309,858	$ 0.03282	262,169
Off Peak Energy		7,861,106	$ 0.02596	204,074	$ 0.03282	258,002
Minimum Energy				(23,990)		(24,224)
Total Calculated at Base Rates				$ 687,675		$ 694,312
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 687,675		$ 694,312
Fuel Clause Billings - proforma for rollir				28,561		28,561
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				$ -	0.03282	-
Total				$ 716,236		$ 722,873
Proposed Increase						6,637
Percentage Increase						0.93%

Attachment to Response to Question No. 2(b)
Page 1 of 2
Seelye

KENTUCKY UTILITIES COMPANY
Calculations of Proposed Rate Increase
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	Bills / KW	Total KWH	Present Rates	Calculated Revenue at Present Rates	Proposed Rates	Calculated Revenue at Proposed Rates
STOD-S Rate Code 584 (Customers Eligible for Service Under Rate TOD-Secondary)						
Customer	612		$ 90.00	$ 55,080	$ 90.00	55,080
Demand (KW)	351,379		$ 7.65	2,688,050		
On-Peak Demand (KW)	351,379				6.39	2,245,312
Off-Peak Demand (KW)	348,514				1.27	442,612
Minimum Demand				-		-
On Peak Energy		94,624,461	$ 0.03879	3,670,483	$ 0.03282	3,105,575
Off Peak Energy		94,679,823	$ 0.02596	2,457,888	$ 0.03282	3,107,392
Minimum Energy				(251,753)		(254,154)
Total Calculated at Base Rates				$ 8,619,748		$ 8,701,818
Correction Factor				1.000000		1.000000
Total After Application of Correction Factor				$ 8,619,748		$ 8,701,818
Fuel Clause Billings - proforma for rollin				308,031		308,031
VDT Amortization & Surcredit Adjustment				-		-
Adjustment to Reflect Year-End Customers				-		-
Adjustment to Reflect Temperature Normalization				(32,622)	0.03282	(32,622)
Total				$ 8,895,156		$ 8,977,226
Proposed Increase						82,070
Percentage Increase						0.92%

Attachment to Response to Question No. 2(b)
Page 2 of 2
Seelye

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 3

Responding Witness: William Steven Seelye

Q-3. Refer to Volume 1 of 5 of KU's application, Tab 24. Provide the supporting calculations for the STOD class percentage increase of .92 percent.

A-3. See response to Question No. 2(b).

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 4

Responding Witness: Shannon L. Charnas

Q-4. Refer to Volume 4 of 5 of KU's application, the Testimony of S. Bradford Rives ("Rives Testimony") at page 10. Line 3 states that an "adjustment is necessary to eliminate accrued revenues associated with the ECR, MSR, VDT, and FAC rate mechanisms." Was an adjustment also made to remove accrued expenses associated with the accrued revenues? If yes, state in what adjustment(s) this is done. If no, explain why not.

A-4. There was not an adjustment made to remove accrued expenses associated with the accrued revenues listed on Commission's First Data Request Reference Schedule 1.09 of Exhibit 1. This is due to the fact that there are no accrued expenses associated with those accrued revenues listed. ECR and FAC revenue are accrued due to the lag in recovery of expenses from customers. MSR and VDT are reductions in revenue due to customers' share of the savings related to these two mechanisms. Accordingly, there are no expenses associated with these mechanisms.

See the response to Question No. 58 for further explanation regarding unbilled/accrued expenses.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 5

Responding Witness: S. Bradford Rives

Q-5. Refer to page 19 of the Rives Testimony. Mr. Rives states that KU has a target capital structure of the midpoint of the range for an "A" rating as published by Standard and Poor's. Provide KU's current rating.

A-5. KU's long-term credit rating from S&P is BBB+ and the short-term rating is A-2. KU's issuer rating from Moody's is A2 and the commercial paper rating is P-1.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 6

Responding Witness: Lonnie E. Bellar

Q-6. Refer to Exhibit 1, Reference Schedule 1.01 of the Rives Testimony. KU proposes to increase revenue by $18,568,431 for the elimination of the Merger Surcredit. Explain why this amount does not equal the $18,968,825 set out as the annual amount in CN 2002-00429.

A-6. The actual Merger Surcredit revenues for the test period ending April 30, 2008 are $18,568,431. This amount eliminates 100% of the Merger Surcredit from test period revenues. This amount does not equal the $18,968,825 due to actual billing variances. The cumulative difference between actual billing amounts and the Merger Surcredit tariff amounts are trued-up through the balancing adjustment as prescribed in the tariff.

12 Months Ended April 2008	Actual Billing	Per Tariff	Balancing Adjustment
Savings to be Distributed	$17,498,539	$17,898,933	$ 400,394
Settlement Payment Amortization	1,069,892	1,069,892	0
Total Merger Surcredit	$18,568,431	$18,968,825	$ 400,394

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 7

Responding Witness: Shannon L. Charnas

Q-7. Refer to Exhibit 1, Reference Schedule 1.09 of the Rives Testimony. Provide the calculation supporting the $25,015,000 shown on this schedule as FAC Accrued Revenue.

A-7.

Description		Amount
Change in FAC accrual due to a decrease in the regulatory lag amount from the beginning of the test year	$	26,028,000
Change in FAC adjustment for over- or under-recovery		(1,013,000)
Net Change in FAC Accrual adjusted on Reference Schedule 1.09	$	25,015,000

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 8

Responding Witness: S. Bradford Rives

Q-8. Refer to Volume 4 of 5 of KU's application, the Testimony of William E. Avera ("Avera Testimony"), at page 9.

a. To the extent that KU's capital requirements are satisfied through its parent, E.ON AG, explain how E.ON AG and ultimately KU actually obtain this capital.

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

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

d. To the extent that KU issues tax exempt debt, explain whether the parent company is liable in any way for repayment.

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

A-8. 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 KU, funds are provided by E.ON AG in two ways. First, Fidelia (another wholly owned subsidiary of E.ON AG) loans funds to KU as described in b. below. Second, E.ON U.S. has, from time to time, contributed funds to KU 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. KU does not subscribe to ratings from Fitch, therefore Fitch plays no role in the issuance of tax exempt debt securities for KU. KU is currently rated BBB+ by Standard and Poor's and A2 by Moody's. The Order obtained from the Commission for Case No. 2007-00548 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 KU from international investment banks for a secured bond issued by KU 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 KU. International banks providing the quotes mentioned above use the credit ratings from S&P and Moody's for KU in determining the rate of interest to be quoted on a secured bond that would be issued by KU.

c. KU does not subscribe to ratings from Fitch, therefore Fitch plays no role in the issuance of tax-exempt debt securities for KU. KU 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 KU 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 KU in connection with financing portions of KU'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 KU'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. KU'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, KU is entitled to apply for and receive an allocation from the Committee.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 9

Responding Witness: William E. Avera

Q-9. Refer to pages 10-13 of the Avera Testimony. In support of his proposed return on equity ("ROE") of 11.25 percent, Mr. Avera discusses the volatility of commodity energy costs and states that Moody's Investors Service warned utility investors of "extremely volatile" commodity costs. Mr. Avera ends this discussion on page 13 by stating that although KU has a FAC mechanism in place, because of lag between incurring fuel costs and recovering costs from ratepayers, KU may still need to finance deferred power production and supply costs.

a. State whether, during the test year, KU financed deferred power production or supply costs.

b. Would Mr. Avera agree that the fact that KU does have an FAC mechanism in place makes it less risky financially and supports a lower ROE than for those without this mechanism?

A-9. a. KU has not financed deferred power production or supply costs during the test year. In evaluating the risks and required return associated with KU, investors are forward-looking and recognize the potential for deferred power cost recovery, even with the FAC. Thus, regardless of whether KU financed deferred power production or supply costs during the test year, this potential lag is one uncertainty considered by investors in their evaluation of a required ROE for KU.

b. Adjustment mechanisms and contractual arrangements that enable utilities to implement rate changes to pass-through fluctuations in fuel costs are widely prevalent in the industry. Similarly, the firms in Dr. Avera's Non-Utility Proxy Group also have the ability to alter prices in response to rising production costs, with the added flexibility to withdraw from the market altogether. As a result, the mitigation in risks associated with utilities' ability to attenuate the impact of power cost volatility is already reflected in the estimated costs of equity and ROE recommendation developed in Dr. Avera's testimony. Thus, the fact that KU does have an FAC mechanism moderates the risks that it would otherwise face without such a mechanism, but it does not imply less risk than other industry participants.

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

Question No. 10

Responding Witness: Robert M. Conroy

Q-10. Refer to page 13 of the Avera Testimony. Explain whether KU has requested that the Commission alter its FAC mechanism to recover costs in a more timely fashion in order to alleviate investor concerns regarding the lag between expenses incurred and recovered through rates.

A-10. KU has not requested that the Commission alter the fuel adjustment clause.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
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Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 11

Responding Witness: William E. Avera

Q-11. Refer to pages 14-15 of the Avera Testimony.

a. Kentucky is not a restructured state. Explain 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 KU would be able to recover its costs in a timely fashion or in a manner that would lead investors to view the regulatory environment as hostile.

A-11. a. Dr. Avera's testimony at pages 14-15 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 14-15.

b. Dr. Avera's testimony at pages 14-15 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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
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Response to Second Data Request of Commission Staff
Dated August 27, 2008

Question No. 12

Responding Witness: William E. Avera

Q-12. Refer to pages 15-16 of the Avera Testimony. Provide a copy of Moody's Investors Service, "Credit Opinion: Kentucky Utilities Co.," referenced in footnote 31.

A-12. A copy of the requested document is included in Dr. Avera's work papers provided in response to the AG-1 Question No. 81 at WEA-WP45.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 13

Responding Witness: William E. Avera

Q-13. Refer to pages 15-16 of the Avera Testimony. Mr. Avera discusses the increased environmental pressured faced by utilities and the significant costs. While Mr. Avera notes that KU benefits from an Environmental Cost Recovery ("ECR") mechanism, he states that Moody's Investors Service "would consider a downgrade to the Company's credit ratings if significant changes were made to the ECR." Absent any changes to the ECR mechanism, would Mr. Avera agree that the fact that KU does have an ECR mechanism in place makes it less risky financially and supports a lower ROE than for those without this mechanism?

A-13. As discussed in Dr. Avera's testimony, his recommended ROE was evaluated by reference to proxy groups of firms with risks comparable to those of KU. Because the impact of the ECR is considered by the investment community in its assessment of KU's ongoing risks, the fact that KU benefits from this mechanism does not support an ROE below the results implied for the other companies included in Dr. Avera's analyses. Further, while the ECR is supportive of KU's financial integrity, utilities across the U.S. – including those in the Utility Proxy Group used to estimate the cost of equity – are increasingly availing themselves of similar adjustments designed to insulate against the risks associated with fluctuating costs and regulatory lag.

KENTUCKY UTILITIES COMPANY

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CASE NO. 2007-00565

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

Question No. 14

Responding Witness: William E. Avera

Q-14. Refer to page 23 of the Avera Testimony and Schedule WEA-1. Provide a schedule which lists each of the 17 utilities in the Utility Proxy Group plus KU 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-14. 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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 15

Responding Witness: William E. Avera

Q-15. Provide the most current Value Line Profile Sheet for KU and for each of the 17 utilities listed in Mr. Avera's Utility Proxy Group.

A-15. 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 KU. The most recent Value Line Investment Survey reports for each of the firms in the Utility Proxy Group are attached.

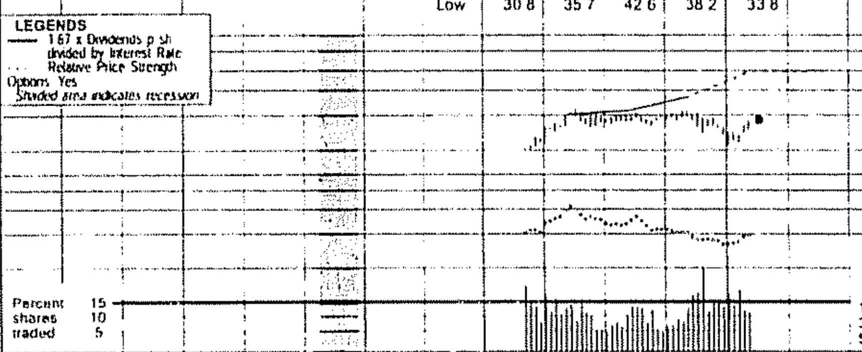
ALLETE NYSE-ALE

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 11/9/07
SAFETY 2 New 10/1/04
TECHNICAL 2 Raised 6/13/08
BETA .90 (1.00 = Market)

	2004	2005	2006	2007	2008
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



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

% 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.

1998	1999	2000	2001	2002	2003	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	14.8	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	+.3
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.

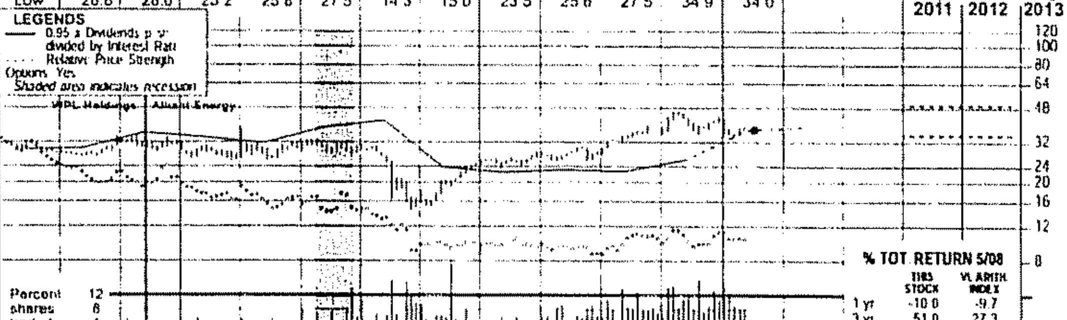
Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	NMF
Earnings Predictability	NMF

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

TIMELINESS 3 Raised 2/15/06
SAFETY 2 Raised 9/28/07
TECHNICAL 3 Lowered 5/30/08
BETA .80 (1.00 = Market)

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	25.8	27.5	14.3	15.0	23.5	25.6	27.5	34.9	34.0



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	148	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	5.82	4.52	4.19	4.69	5.46	4.33	5.12	5.55	6.10	"Cash Flow" per sh	7.55
1.28	2.19	2.47	2.42	1.16	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 ■ †	1.92
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	20.85	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	11.8	12.6	19.9	12.7	14.0	12.6	16.8	15.1	Bold figures are		Avg Ann'l P/E Ratio	13.0
1.31	.74	.77	.65	1.09	.72	.74	.67	.91	.80	Value Line		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%	estimates		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 ($mill)	4500
103.4	178.2	203.1	194.9	113.1	176.6	229.5	337.8	260.1	320.8	325	340	Net Profit ($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%	8.1%	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 $555.7 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 (¢)	5.28	5.98	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	696.8	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, (56¢); '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

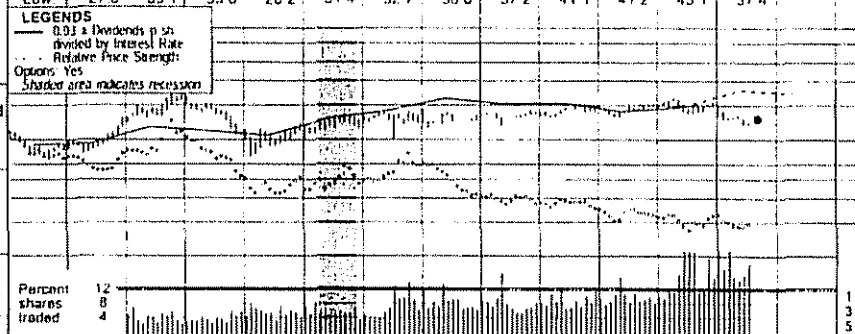
CON. EDISON NYSE-ED

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

TIMELINESS 3 Raised 6/11/06
SAFETY 1 New 7/27/90
TECHNICAL 3 Raised 6/6/08
BETA .75 (1.00 = Market)

	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
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

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



Target Price Range 2011 | 2012 | 2013
120 100 80 64 48 32 24 20 16 12 8

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

Percent shares traded 12 8 4

% TOT. RETURN 7/08

	THIS STOCK	VL ARITH INDEX
1 yr	-4.2	-12.7
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	4.38	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	2.18	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	5.66	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	25.81	26.71	27.66	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%

Calendar	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

Calendar	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

Calendar	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.: 212-460-3900. 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 elec. common equity: '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

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

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	20.3	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

2011-13 PROJECTIONS

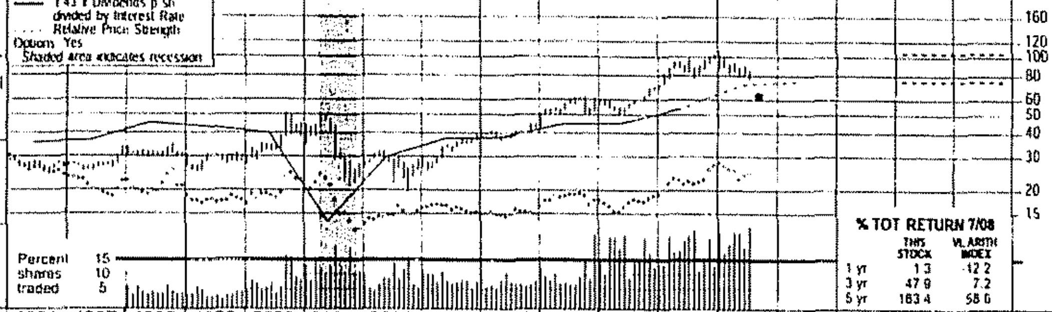
	Price	Gain	Ann'l Total Return
High	105	(+70%)	16%
Low	75	(+20%)	8%

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	120372	120891



% TOT. RETURN 7/08

	THIS STOCK	VL ARITH. INDEX
1 yr	1.3	-12.2
3 yr	47.9	7.2
5 yr	163.4	58.0

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	6.61	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	23.48	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	178.30	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	15.3	13.2	15.8	16.4	12.1	11.8	12.5	16.0	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%
						3358.1	3786.2	3878.5	3928.3	4703.0	9703.0	12550	17132	19285	21193	20100	21800	Revenues ($mill)	28250
						327.7	339.9	358.5	366.3	372.1	472.2	567.8	619.9	696.8	796.4	790	1075	Net Profit ($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%

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 $100.0 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)

ELECTRIC OPERATING STATISTICS

	2005	2006	2007
% Change Retail Sales (KWH)	+3.0	-3.8	+3.3
Avg. Indust. Use (MWH)	762	877	647
Avg. Indust. Revs. per KWH (¢)	8.80	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: $4.09/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

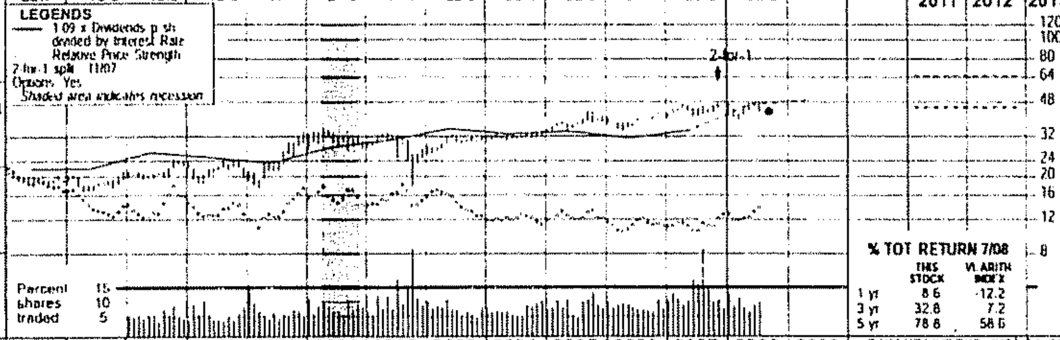
DOMINION RES. NYSE-D

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 5/2/08
BETA .75 (1.00 = Market)

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	

LEGENDS
— 1.09 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 11/07
Options: Yes
Shaded area indicates recession



2011-13 PROJECTIONS

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

Insider Decisions

	O	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

% TOT. RETURN 7/08

	THIS STOCK	VL ARITH. INDEX
1 yr.	8.6	-12.2
3 yr.	32.8	7.2
5 yr.	78.8	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	13.19	13.02	13.18	13.36	20.44	15.65	14.81	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	4.18	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	2.13	1.50	2.40	2.13	3.05	3.30	Earnings per sh A	4.00
1.20	1.24	1.28	1.28	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		Avg Ann'l P/E Ratio	14.0
.87	.84	.91	1.03	.93	.72	1.28	.83	1.26	1.07	.66	.87	.80	1.33	.86	1.09	Value Line		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%	estimates		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 ($mill)	18300
400.0	639.0	624.0	775.0	1378.0	1261.0	1425.0	1050.0	1704.0	1414.0	1785	1965	Net Profit ($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 ($mill)	33400
10637	10764	14849	16681	20257	25850	26716	28940	29382	21352	24025	27000	Net Plant ($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%

Cal-endar	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

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2005	.63	.49	.02	.38	1.50
2006	.78	.36	.94	.32	2.40
2007	.69	.48	.44	.51	2.13
2008	1.01	.47	.87	.70	3.05
2009	1.05	.55	.95	.75	3.30

Cal-endar	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 $243 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

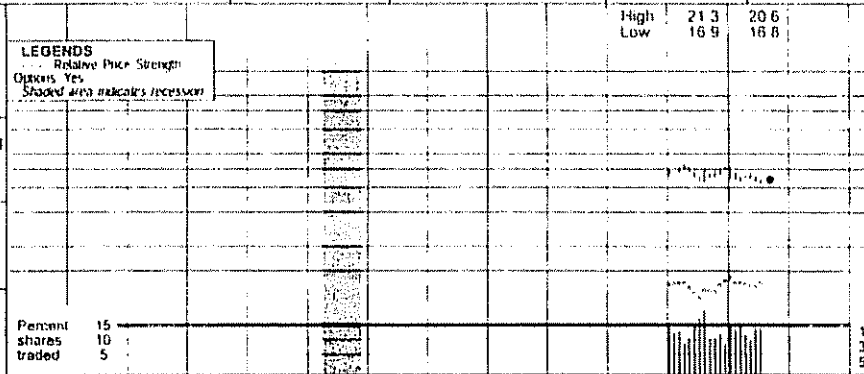
	Price	Gain	Ann'l Total Return
High	25	(+40%)	13%
Low	19	(+5%)	7%

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	384	359
to Sell	308	275	318
Hld's(000)	743605	759575	710165



	2007	2008
High	21.3	20.6
Low	16.9	16.8

Target Price Range 2011 | 2012 | 2013

% TOT. RETURN 7/08

	THIS STOCK	VL ARITH. INDEX
1 yr	8.2	-12.2
3 yr	—	7.2
5 yr	—	56.6

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.

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	© VALUE LINE PUB., INC.	11-13
--	--	--	--	--	--	--	--	8.44	10.08	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
--	--	--	--	--	--	--	--	--	16.1	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%

Calendar	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

Calendar	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

Calendar	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

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	37.1	42.3	50.6	64.5	66.8	89.6	99.4

TIMELINESS 2 Raised 6/6/08
SAFETY 2 New 3/31/06
TECHNICAL 3 Lowered 5/5/08
BETA .85 (1.00 = Market)

2011-13 PROJECTIONS

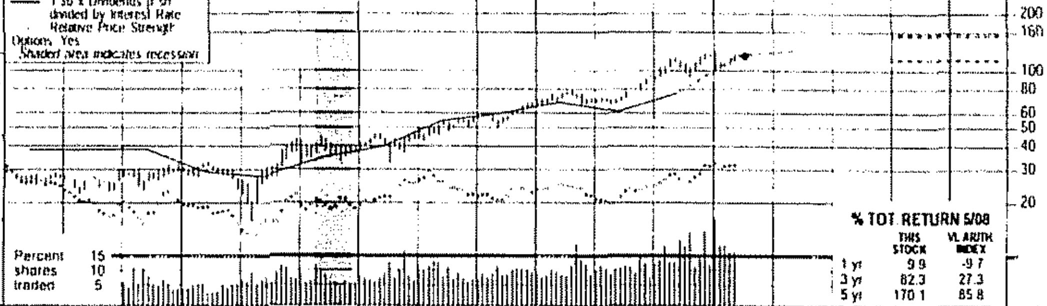
	Price	Gain	Ann'l Total Return
High	155	(+30%)	10%
Low	115	(-5%)	3%

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	156325	154792



% 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	85.8

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	46.69	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	8.33	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	4.64	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	36.26	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	.79	.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	3.5%
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.** $3248 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%

Calendar	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

Calendar	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

Calendar	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 Quachita 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

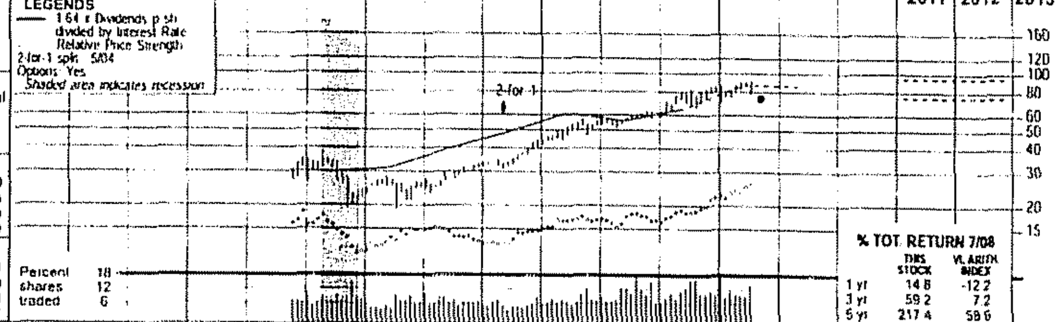
EXELON CORP. NYSE-EXC

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 6/3/05
TECHNICAL **2** Raised 8/15/08
BETA .85 (1.00 = Market)

LEGENDS
— 1.64 x Dividends p sh divided by Interest Rate
Relative Price Strength
2-for-1 split 5/04
Options: Yes
Shaded area indicates recession

	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



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

% TOT. RETURN 7/08

	THIS STOCK	VL ARITH. INDEX
1 yr	14.8	-12.2
3 yr	59.2	7.2
5 yr	217.4	58.6

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	12.84	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	664.20	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%	18.8%	19.5%	23.6%	23.7%	26.9%	**26.0%**	**24.5%**	Return on Com Equity E	**26.0%**
--	--	7.8%	10.1%	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** $6892 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%

Cal-endar	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**

Cal-endar	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**

Cal-endar	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

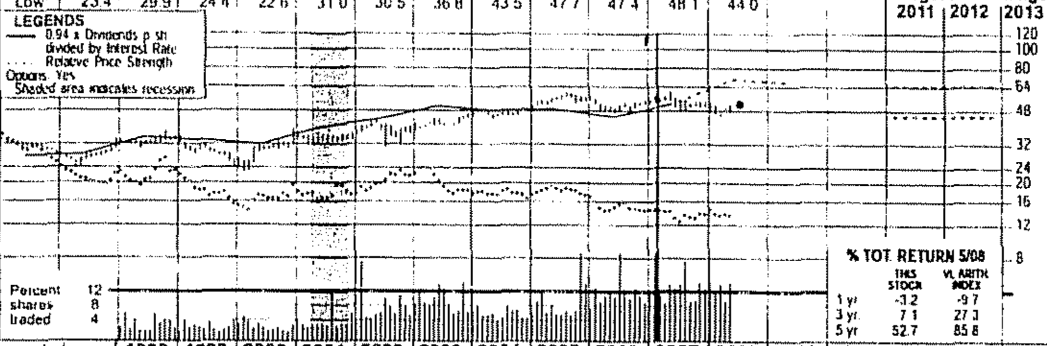
RECENT PRICE 52.12 | P/E RATIO 14.3 (Trailing: 20.4 Median: 14.0) | RELATIVE P/E RATIO 0.88 | DIV'D YLD 5.2% | VALUE LINE

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	35.8	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

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

Target Price Range
2011 | 2012 | 2013



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.	-1.2	-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	2.24	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	32.01	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		Avg Ann'l P/E Ratio	12.5
.98	.75	.79	.64	.76	.85	.61	.71	.79	1.13	Value Line		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%	estimates		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 ($mill)	14450
49.8	62.7	67.4	60.7	94.4	94.5	156.2	157.4	151.6	181.0	285	300	Net Profit ($mill)	350
32.3%	32.2%	6.7%	5.6%	20.6%	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%	10.6%	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 $2446 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 $8.3 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 (KWH)	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 9/30/06
SAFETY **1** Raised 8/17/01
TECHNICAL **2** Raised 6/6/08
BETA 1.00 (1.00 = Market)

2011-13 PROJECTIONS

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

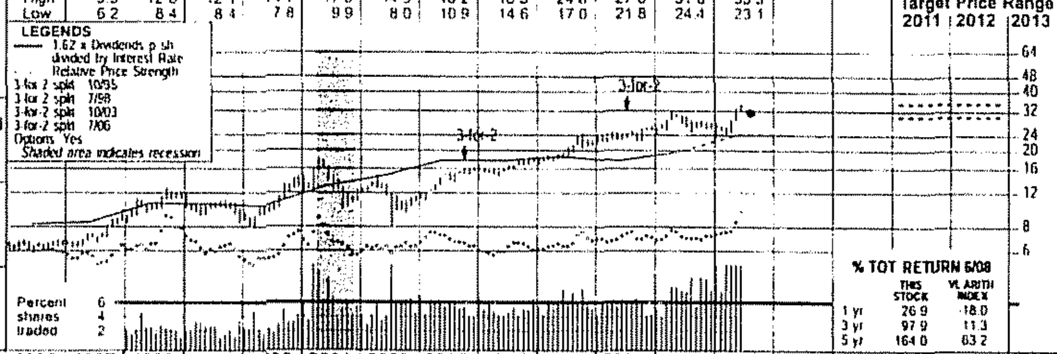
Insider Decisions

	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

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
High	9.9	12.8	12.1	14.7	17.9	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					



% 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	2.18	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	.82	1.08	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	13.8	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%

1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009		11-13
896.6	1279.8	1873.7	2223.6	2004.1	2352.2	2719.3	3455.4	4070.7	4247.9	4825	5080	Revenues ($mill)	6050
74.0	84.1	111.0	149.6	131.8	182.9	212.4	275.1	317.9	322.8	370	385	Net Profit ($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)	+4.8	+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%

Calendar	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

Calendar	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

Calendar	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

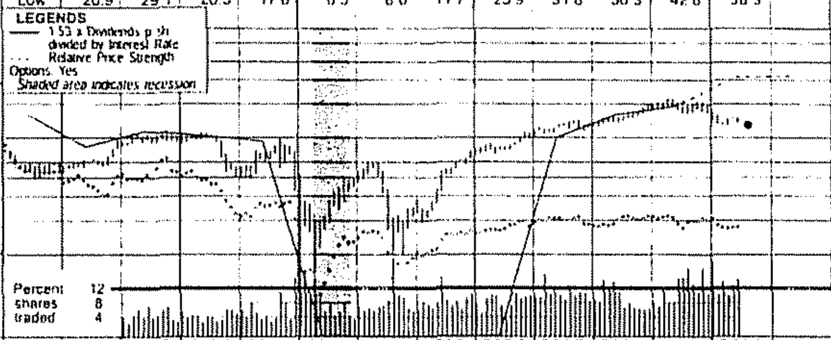
PG&E CORP. NYSE-PCG

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

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

TIMELINESS 3 Raised 7/11/08
SAFETY 2 Raised 5/12/06
TECHNICAL 4 Lowered 7/25/08
BETA .85 (1.00 = Market)

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



Target Price Range 2011 | 2012 | 2013
120
100
80
64
48
32
24
20
16
12
8

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	241684

Percent shares traded 12 8 4

% TOT. RETURN 6/08

	THIS STOCK	VL ARITH. INDEX
1 yr	-0.1	-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	24.26	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	6.19	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	--	4.6	--	9.5	13.8	15.4	14.8	16.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**12.5**
.75	.87	.62	.63	.68	.89	.87	.75	--	.25		.54	.73	.82	.80	.88			Relative P/E Ratio	**.85**
5.6%	5.5%	7.5%	7.1%	7.5%	4.9%	3.8%	4.1%	4.6%	--	--	--	--	2.5%	3.2%	3.0%			Avg Ann'l Div'd Yield	**4.7%**

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)

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%**
16268	14339	10428	12399	8438.0	7815.0	16242	14446	14760	16976	**18200**	**19480**	Total Capital ($mill)	**22310**
17818	16776	16591	19167	16928	18107	18989	19955	21785	23656	**25555**	**26305**	Net Plant ($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%**
8.4%	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%**
8.9%	11.5%	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%**

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: $11.80/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

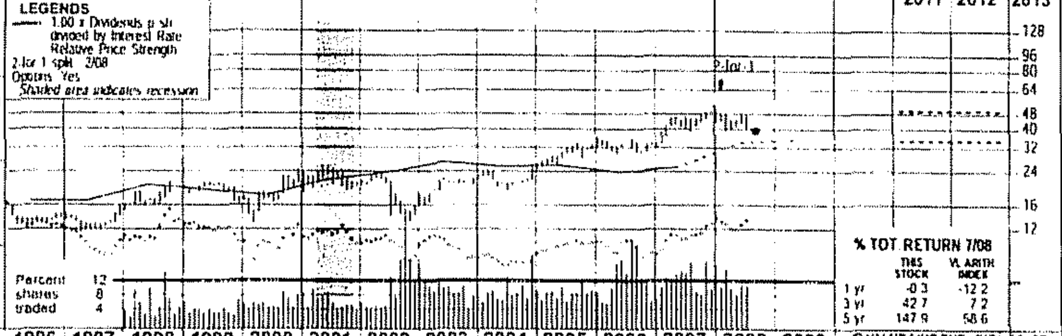
RECENT PRICE	39.39	P/E RATIO	13.2 (Trailing: 13.6 / Median: 13.0)	RELATIVE P/E RATIO	0.86	DIV'D YLD	3.4%	VALUE LINE

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

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
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

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
···· Relative Price Strength
2-for-1 split 2/08
Options: Yes
Shaded area indicates recession



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)	306684	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	2.63	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	1.85	1.86	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	14.3	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%	3.6%	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	© VALUE LINE PUB., INC.	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%

Calendar	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

Calendar	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

Calendar	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: $10.28/sh. (D) Rate base: not 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

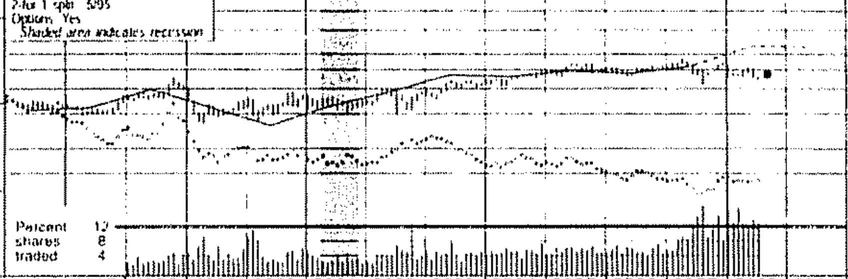
SCANA CORP. NYSE-SCG

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 .60 (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	27.5	21.1	22.0	24.3	23.5	28.1	32.8	36.6	36.9	32.9	35.0

LEGENDS
— 1.09 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 5/95
Options: Yes
Shaded area indicates recession



Target Price Range 2011 | 2012 | 2013
128 — 96 — 80 — 64 — 48 — 40 — 32 — 24 — 16 — 12

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	3	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	2	0	0	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

Percent shares traded 12 8 4

% TOT. RETURN 7/08

	THIS STOCK	VL ARITH. INDEX
1 yr	1.3	-12.2
3 yr	-2.1	7.7
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	19.40	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	5006.0	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%	11.8%	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 (¢)	4.82	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 54% 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

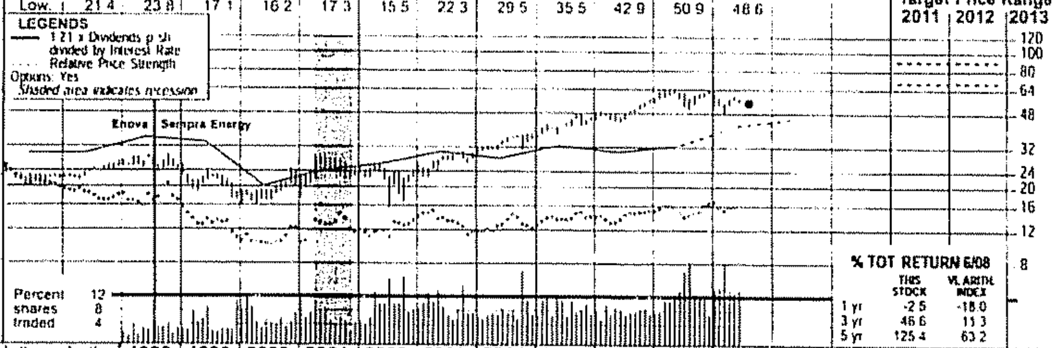
SEMPRA ENERGY NYSE-SRE

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 8/8/03
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	16.2	17.3	15.5	22.3	29.5	35.5	42.9	50.9	48.6	

Target Price Range 2011 | 2012 | 2013



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	29.38	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	12.8	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 ($mill)	18000
5441.0	5394.0	5726.0	6217.0	6832.0	10474	11066	12101	13175	14884	16250	18025	Net Plant ($mill)	21800
6.8%	8.3%	9.0%	10.2%	9.8%	9.6%	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 $4569.0 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%

Calendar	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

Calendar	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

Calendar	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 1/5/01
TECHNICAL 4 Lowered 6/20/08
BETA .90 (1.00 = Market)

2011-13 PROJECTIONS	Price	Gain	Ann'l Total Return
High	35	(+15%)	7%
Low	25	(-20%)	Nil

Insider Decisions

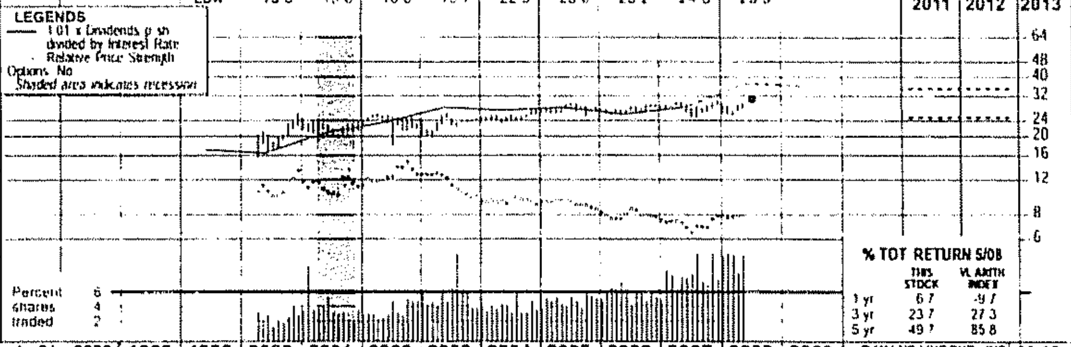
	A	S	O	N	D	J	F	M	A
to Buy	1	0	0	0	0	0	0	0	0
Options	0	0	0	3	0	0	0	0	0
to Sell	0	0	0	2	0	0	0	0	0

Institutional Decisions

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

	2000	2001	2002	2003	2004	2005	2006	2007	2008
High	26 5	24 4	26 1	26 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

LEGENDS
— 1.01 x Dividends p sh divided by Interest Rate
· Relative Price Strength
Options: No
Shaded area indicates recession



Target Price Range
2011 | 2012 | 2013

% TOT. RETURN 5/08

	THIS STOCK	VL ARITH. INDEX
1 yr	6 7	-9 7
3 yr	23 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	2.88	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 ($mill)	**3150**
--	1336.3	1555 8	1595.0	1648.1	2003.7	2156.2	2251 9	2385.5	2539.7	**2655**	**2725**	Net Plant ($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 84 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, 80¢; '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) Electric 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

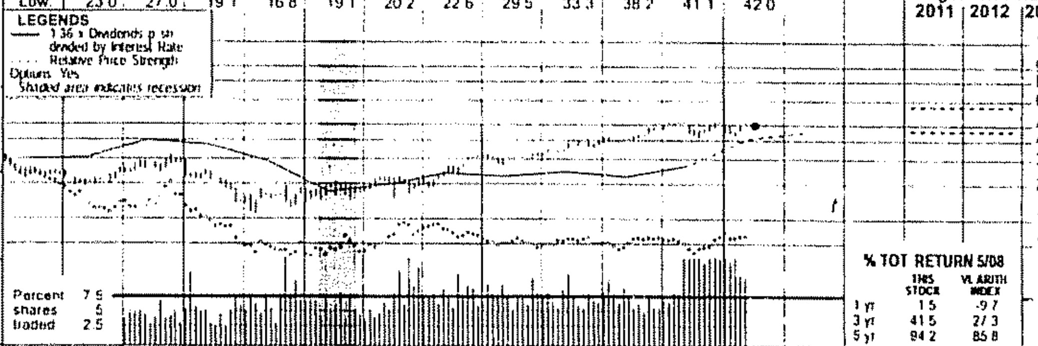
WISCONSIN ENERGY NYSE-WEC

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

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



Target Price Range
2011 | 2012 | 2013

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)	78561	80075	81614

Percent shares traded 7.5 / 5 / 2.5

% TOT RETURN 5/08

	THIS STOCK	VL ARITH INDEX
1 yr	1.5	-9.7
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	15.86	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	3.61	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	1.84	2.32	2.26	1.65	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	Value Line	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	estimates		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%			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 ($mill)	5800
189.3	231.5	132.0	218.8	270.8	269.2	221.2	304.8	313.7	337.7	335	385	Net Profit ($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%	5.8%	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	5992.8	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 nonutility 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

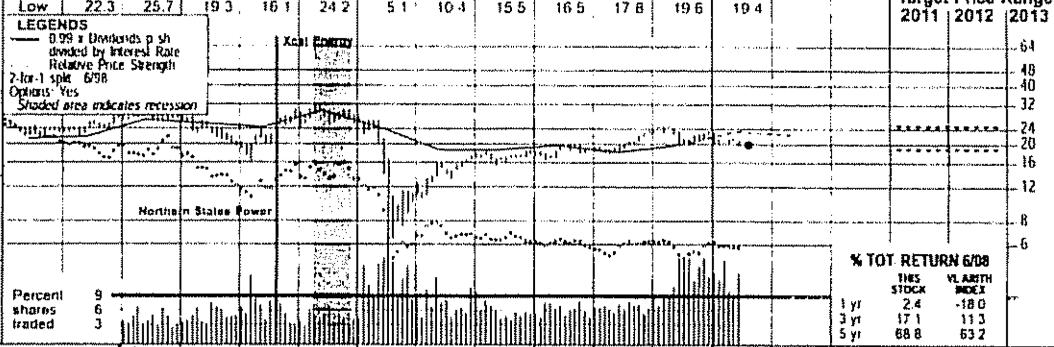
XCEL ENERGY NYSE-XEL

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%

TIMELINESS 3 Lowered 3/16/07
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



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

% 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

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	23.66	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	13.87	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%	32.8%	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%

Calendar	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**

Calendar	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**

Calendar	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. inc, 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. P.S. 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, P.S. 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¢; '08, 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

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 16

Responding Witness: William E. Avera

Q-16. Refer to page 25 of the Avera Testimony. Provide a copy of the workpapers supporting the constant growth form of the DCF model and a detailed explanation of how the stock prices were estimated to determine the expected dividend yield.

A-16. Please refer to Dr. Avera's work papers provided in response to the AG-1 Question No. 81 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 AG-1 Question No. 81 at WEA-WP34.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 17

Responding Witness: William E. Avera

Q-17. Refer to pages 32-33 of the Avera Testimony.

a. Provide a copy of the relevant pages in the FERC document cited in footnote 47 that discuss the 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 specific 2004 case or was it meant to be a hard and fast rule to be applied as a ceiling in all cases thereafter?

A-17. a. A complete copy of the document cited in footnote 47 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.

KU Response to PSC-2 Question 17(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.

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. Requests for Rehearing and/or Clarification

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

[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

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[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.

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-

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[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. <u>Compliance Filing and Responsive Pleadings</u>

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. <u>Commission Finding</u>

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

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[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

[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. <u>Requests for Rehearing</u>

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. <u>Compliance Filing</u>

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]

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[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. <u>Commission Finding</u>

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. <u>Tariff Administration and Design</u>

1. <u>The March 24 Order</u>

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. <u>Compliance Filing</u>

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]

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[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. Responsive Pleadings

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

[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. <u>Compliance Filing</u>

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. <u>Commission Finding</u>

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. Commission Finding

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.

<u>The Commission orders</u>:

(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

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).

KU Response to PSC-2 Question 17(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. Description of Formula Rate

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.

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[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

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[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. <u>100 Percent of CWIP</u>

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. Protests

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. Commission Determination

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

[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;

> 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:

[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. <u>Total Package</u>

a. <u>PATH's proposal</u>

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

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[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]

[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. PATH's Answer

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

[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. <u>Income Taxes</u>

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

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[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

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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 35-36 of the Avera Testimony and Schedule WEA-3. Provide an explanation of why the logic FERC applied to returns for regulated firms at the federal level should apply to firms operating in open competitive markets.

A-18. 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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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 38 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 average stock prices?

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-19. 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 attached Excel spreadsheet.

	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).

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 20

Responding Witness: William E. Avera

Q-20. Refer to Schedule WEA-3, page 3 of 3, of the Avera Testimony. Explain why no estimates were eliminated for being high outliers.

A-20. As indicated in Dr. Avera's testimony, his evaluation of the cost of equity estimates for the firms in the Non-Utility Proxy Group was consistent with the approach he applied to the firms in the Utility Proxy Group. No high-end values were eliminated on page 3 of Schedule WEA-3 because, compared with the balance of the remaining estimates for the firms in the Non-Utility Proxy Group, the results shown there were not extreme outliers. For example, the highest value shown on page 3 of Schedule WEA-3 is 16.2 percent. This value is over 100 basis points less than the 17.7 percent threshold applied by FERC and falls well below the high-end outliers that Dr. Avera eliminated. A 16.2 percent cost of equity estimate may exceed investors' requirements just as the 8.1 percent value shown on page 1 of Schedule WEA-3 is assuredly far below investors' required rate of return.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 21

Responding Witness: Robert M. Conroy

Q-21. Refer to page 4 of the Conroy Testimony. Mr. Conroy states that LG&E and KU have not been able to completely harmonize their rate schedules. Explain why the companies have been unable to do so.

A-21. 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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 22

Responding Witness: Robert M. Conroy

Q-22. Refer to line 5, page 9 and line 19, page 11 of the Conroy Testimony. In both instances, Mr. Conroy refers to an annual minimum cost of $918,200. Did Mr. Conroy intend to state the amount at $918?

A-22. Yes. The annual minimum cost referenced should be $918.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 23

Responding Witness: Robert M. Conroy

Q-23. Refer to Exhibit 1, page 5 of 24 of the Conroy Testimony. In column 11, explain why the customer charge revenue of $8,720 is not included in the total.

A-23. The customer charge revenue of $8,720 should have been included in the total. Attached are revisions to page 1 and 5 of Exhibit 1 of Conroy's testimony.

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

	As Billed Base Rates Revenues	FAC Rollin Rates For a Full Year		ECR Rollin Rates For a Full Year	
		Calculated Base Rates Revenue	Increased Revenue	Calculated Base Rates Revenue	Increased Revenue
Residential Rate - RS (Rate Code 010, 050)	$ 170,338,466	$ 184,540,823	$ 14,202,357	$ 188,421,833	$ 3,881,009
Residential Rate - RS (Rate Code 020, 060, 080)	194,351,991	207,119,436	12,767,444	211,555,693	4,436,258
General Service Rate GS - Secondary	121,479,709	129,652,783	8,173,074	132,313,364	2,660,581
General Service Rate GS - Primary	2,654,163	2,827,648	173,485	2,890,020	62,372
All Electric School Service Rate - AES	6,648,873	7,194,795	545,922	7,350,487	155,692
Large Power Rate LPS - Secondary	186,103,586	204,356,034	18,252,448	208,817,741	4,461,707
Large Power Rate LPP - Primary	70,244,702	78,018,953	7,774,251	79,627,495	1,608,542
Large Power Rate LPT - Transmission	1,110,048	1,228,340	118,293	1,254,069	25,729
Small Time-of-Day - STODS Secondary	7,580,016	8,469,363	889,347	8,619,748	150,385
Small Time-of-Day - STODP Primary	607,081	676,281	69,199	687,676	11,395
Small Time-of-Day - STODT Transmission	-	-	-	-	-
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	107,983,348	120,963,560	12,980,212	123,483,561	2,520,001
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	32,985,640	36,725,123	3,739,483	37,497,758	772,635
Curtailable Service Rider Credits - Primary - LCI -TOD Primary	(96,313)	(96,313)	-	(96,313)	-
Curtailable Service Rider Credits - Transmission -LCI-TOD Transmission	(5,446,292)	(5,446,292)	-	(5,446,292)	-
Large Industrial Time of Day - LITOD	19,489,144	21,094,596	1,605,452	21,293,989	199,393
Coal Mining Power Service Rate - MP Primary	5,800,666	6,278,689	478,023	6,430,565	151,877
Coal Mining Power Service Rate - MP Transmission	3,326,359	3,642,689	316,330	3,723,197	80,508
Large Mine Power Time-of-Day Rate - LMP-TPD Primary	4,055,754	4,448,718	392,964	4,562,563	113,845
Large Mine Power Time-of-Day Rate - LMP-TPD Transmission	11,327,500	12,493,982	1,166,482	12,790,113	296,131
Street Lighting - SL	6,845,641	7,038,223	192,583	7,169,559	131,336
Decorative Street Lighting - SLDEC	1,321,287	1,340,556	19,268	1,364,718	24,162
Private Outdoor Lighting - POL	3,767,361	3,909,679	142,318	3,983,877	74,198
Customer Outdoor Lighting - OL	5,549,604	5,764,477	214,873	5,873,653	109,176
TOTAL	$ 958,028,333	$ 1,042,242,142	$ 84,213,809	$ 1,064,169,074	$ 21,926,931

KENTUCKY UTILITIES COMPANY
Calculations showing the effect on Base Rate Revenue of the ECR and FAC Roll-in's for a full year
Based on Sales for the 12 months ended April 30, 2008

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
		Base Rates Billings During 12 Month Period - As Billed					Fuel Clause Rollin Rates - Full Year				ECR Rollin Rates - Full Year			
	Bills	May07-Nov07 Pre-Rollin KWH	Dec07-Apr08 Post-Rollin KWH	P.S.C. 13 Effective 3/5/2007	P.S.C. 13 Effective 12/3/2007	Base Rates Billings	Bills	Total KWH	P.S.C. 13 Effective 12/3/2007	Calculated Base Rates Billing	Bills	Total KWH	P.S.C. 13 Effective 5/2/2008	Calculated Base Rates Billing
GSP - Rate Codes 111, 151														
Customer Charges	872			$ 10.00	$ 10.00	$ 8,720	872		$ 10.00	$ 8,720	872		$ 10.00	$ 8,720
All KWH		22,733,271	20,987,413	$ 0.05818	$ 0.06599	2,707,581		43,720,684	$ 0.06599	2,885,128		43,720,684	$ 0.06745	2,948,960
Minimum Energy						75,205				80,120				81,888
Demand Discount						(137,925)				(146,941)				(150,182)
Total Calculated at Base Rates						$ 2,653,580				$ 2,827,027				$ 2,889,386
Correction Factor						0.999780				0.999780				0.999780
Total After Application of Correction Factor						$ 2,654,163				$ 2,827,648				$ 2,890,020
INCREASE IN BASE RATES REVENUE										$ 173,485				$ 62,372
DECREASE IN FAC REVENUE										$ (198,343)				

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 24

Responding Witness: Butch Cockerill

Q-24. Refer to page 2 of the Cockerill Testimony. Mr. Cockerill states that KU and LG&E will eliminate the policy that the companies will pay for customer's meter bases.

a. What was the per unit cost for meter bases during the test year?

b. Explain why KU and LG&E changed their policies.

A-24. a. 100 Amp Residential Base - $18.60
200 Amp Residential Base - $25.65
320 Amp Residential Base - $99.64

b. Historically the Company has furnished meter bases for customers to ensure consistency in the types 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. Based on National Electrical Code requirements, should a meter base be unsafe or in poor condition, KU has and will continue to require replacement of a residential meter base at the customer's expense. 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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 25

Responding Witness: Butch Cockerill

Q-25. Refer to pages 4 and 5 of the Cockerill Testimony. Mr. Cockerill states that in Case No. 2007-00410 the Commission ordered KU and its sister company, Louisville Gas and Electric Company ("LG&E"), to synchronize their collection cycles and late payment policies or explain why it is not appropriate to do so. In this proceeding and in Case No. 2008-00252, KU and LG&E are proposing a collection cycle of 10 days and a late payment penalty if bills are not paid within 15 days.

a. Explain fully why KU is proposing to maintain its existing 10-day collection cycle rather than LG&E's 15-day collection cycle.

b. Why is KU proposing to synchronize its late payment policies with LG&E by adding a penalty to KU?

c. For each rate class, provide the payments received by the 10th day of the date of the bill as a percentage of actual billings for each month.

d. For each rate class, provide the payments received between the 10th and the 15th day of the date of the bill as a percentage of actual billings for each month?

e. For each rate class, provide the payments received after the 15th day of the date of the bill as a percentage of actual billings for each month.

f. Assuming that most schools served under the AES rate use an off-site payment processor, will customers be able to enter into a contract with the utility to provide ample time for processing of the payment without incurring a late penalty charge?

g. Provide a list including name, physical address and mailing address of all locations from which customer monthly bills are sent.

h. Provide the number of billing cycles and the dates bills are sent to customers.

i. Provide a list of all call centers receiving customer inquiries along with the physical address, mailing address, and telephone numbers provided to the customers.

j. Provide a listing of all locations where customer payments are received.

k. Provide a listing of all locations where customer payments are processed (i.e., posted to customer accounts).

l. Provide the time line for the posting of payments to customer accounts.

m. Mr. Cockerill states that "customers whose payments are received more than 10 days after customers' bills are issued will have their behavioral scores affected in the Companies' behavioral scoring systems."

(1) Given that KU currently has a 10-day collection cycle, is this a change in KU's current policy? If yes, explain the changes.

(2) Identify all the ways that a customer can be affected by a negative behavioral score.

A-25. a. As previously stated in case 2007-00410, the current KU collection cycle helps to avoid unnecessary customer confusion that may result when more than one bill is received prior to the time a customer may be disconnected for nonpayment. The 10-day collection cycle normally allows KU to complete the collection process prior to the next regularly scheduled billing date. However, in accordance with 807 KAR 5:006, Section 1(f)(1), KU will never terminate service for non-payment prior to twenty-seven (27) days after the mailing date of the original unpaid bill. LG&E customers have experienced confusion due to receiving multiple bills with varying due dates. Allowing LG&E to move to a 10-day collection cycle will greatly reduce customer confusion and enhance customer satisfaction (see attachment).

b. The addition of the late payment fee for KU customers places the financial responsibility for late payments on the cost-causers which serves to decrease base rates.

c. See attached.

d. See attached.

e. See attached.

f. The Companies disagree with the premise of the question in that there is ample time for processing payments without incurring a late payment charge. KU will not enter into contract agreements to permit variations from the tariff.

g. Bills are mailed from either the Broadway Office Complex located at the corner of 8th Street and Broadway in downtown Louisville, Kentucky or the downtown Lexington Office located on the corner of Vine Street and Quality Street. Their mailing addresses are 820 West Broadway, Louisville, Kentucky, 40202 and One Quality Street, Lexington, Kentucky, 40507.

h. KU has 20 billing cycles per month. Billing dates will vary slightly from month to month. In general, billings occur the first business day following the meter read date.

i. Listed below are the Call Center locations, mailing addresses and customer contact numbers for the call centers.

Louisville Residential Call Center
820 W. Broadway
Louisville, KY 40203

Lexington Residential Call Center
1 Quality St
Lexington, KY 40507

Pineville Residential Call Center
US 25E
Four Mile, KY 40939

Louisville Business Call Center
820 W. Broadway
Louisville, KY 40203

Lexington Business Call Center
1 Quality St
Lexington, KY 40507

KU Customer Service Phone (Business or Residential):
800-981-0600 (toll-free)
859-255-0394 (Local customer service number for Lexington and surrounding area)
859-367-1200 (Local number for Lexington area Business customers)
800-383-5582 (toll-free KU Business customers)

LG&E Customer Service Phone (Business or Residential):
800-331-7370 (toll-free)
502-589-1444 (Local customer service number in Louisville)
502-627-3313 (Local business service center in Louisville)
502-589-3500 (Local outage reporting number)
502-589-5511 (Local gas emergency number)

j. KU customer payments can be received at the following locations:
- Any of KU's 24 walk-in center locations throughout the state (see Attachment 1).

- Any of 26 CheckFree locations located throughout KU service territory (see Attachment 2).
- Mail-in payments are received at P.O. Box 536200, Atlanta, GA., 30353-6200 – the site of our mail payment processor, Regulus Corporation.
- Customers can pay via auto-debit from a checking or savings account.
- Customers can pay by credit/debit/ATM card or electronic check, either over the phone or on-line at www.eon-us.com, or via their personal financial software, such as MS Money, Quicken, bank proprietary sites, etc.

k. All customer payments, regardless of where or how received, are processed (posted to customer accounts) at LG&E's Broadway Office Complex, 820 West Broadway, Louisville, KY., 40202

l. All payments are posted to customer accounts on the evening of receipt, assuming the customer has included an account number or other identification that allows the proper account to be located. This includes all walk-in or over the counter payments, and all electronic payment files received from the various sources listed in response d above, including mail-in payments processed in Atlanta. The Atlanta site processes payments on a 24 x 7 basis, with mail pick-up times of 5:00 p.m., 10:00 p.m., midnight, 3:00 a.m., 6:00 a.m., 9:00 a.m., 11:00 a.m. (M-F only), and noon. All payments received in Atlanta are processed on the day of receipt.

m. (1) No, this is not a change in KU's current policy. Since the implementation of behavioral scoring in September, 2005, customers' accounts have been scored two days after the bill due date.

m. (2) 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 KU 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.

Answer to Q3 and Q4 of the KPSC Commission Staff's First Data Request – Case No. 2007-00410 – Chart showing illustrative dates of the *existing* LG&E 15-day due date collection cycle and the *proposed* LG&E 10-day due date collection cycle – Example is based on LG&E Meter Read Cycle 1 for August 2007

Sun	Mon	Tue	Wed	Thu	Fri	Sat
			1 AUGUST Both: Meter Read date for August bill	2 Q4-Proposed: Bill mailed (rendered) for August bill	3 **Q3-Current: Bill mailed (rendered) for August bill**	4
5	6	7	8	9	10	11
12	13 Q4-Proposed: Bill Due Date for August bill	14	15	16	17	18
19	20 **Q3-Current: Bill Due Date for August bill** Q4 – Proposed: Brown Bill issued	21	22	23	24 **Q3 – Current: Brown Bill issued for August bill**	25
26	27	28	29	30	31 ***Q3 – Current: Meter Read date for September bill*** Q4-Proposed: Brown Bill Due Date for August bill ***Q4 – Proposed: Meter Read date for September bill***	1 **SEPTEMBER**
2	3 **HOLIDAY**	4 Q4-Proposed: Disconnect Date for August bill ***Q4 – Proposed: Bill mailed (rendered) for September bill***	5 ***Q3 – Current: Bill mailed (rendered) for Sept. bill***	6	7 **Q3-Current: Brown Bill Due Date for August bill**	8
9	10 **Q3-Current: Disconnect Date for August bill**	11	12	13	14 ***Q4 Proposed: Bill Due Date for Sept. bill***	15
16	17	18	19	20 ***Q3-Current: Bill Due Date for Sept. bill***	21	22

		A. 25c	**A. 25d**	**A. 25e**
		Payments as a % of Total Actual Bills for the Month		
Month	Rate Class	Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
May-07	COMMERCIAL-L-P	10.92%	9.43%	3.46%
	INDUSTRIAL-L-P	12.20%	5.75%	3.52%
	MINE-POWER	1.43%	1.19%	0.42%
	MUNICIPAL-PUMP	0.28%	0.06%	0.01%
	OTHER-PUB-AUTH	6.44%	0.77%	0.55%
	PUBLIC-STREET	0.83%	0.04%	0.04%
	RESIDENTIAL	12.88%	9.71%	5.77%
Jun-07	COMMERCIAL-L-P	12.49%	9.25%	3.73%
	INDUSTRIAL-L-P	12.12%	7.17%	2.24%
	MINE-POWER	1.31%	0.94%	0.38%
	MUNICIPAL-PUMP	0.32%	0.04%	0.01%
	OTHER-PUB-AUTH	4.62%	0.80%	0.74%
	PUBLIC-STREET	0.67%	0.04%	0.03%
	RESIDENTIAL	12.98%	10.29%	5.97%
Jul-07	COMMERCIAL-L-P	12.01%	9.88%	3.68%
	INDUSTRIAL-L-P	11.30%	6.72%	2.40%
	MINE-POWER	1.41%	1.07%	0.15%
	MUNICIPAL-PUMP	0.26%	0.05%	0.02%
	OTHER-PUB-AUTH	3.65%	1.43%	0.41%
	PUBLIC-STREET	0.67%	0.04%	0.03%
	RESIDENTIAL	14.67%	11.16%	6.26%
Aug-07	COMMERCIAL-L-P	7.95%	10.79%	5.97%
	INDUSTRIAL-L-P	7.62%	6.31%	5.38%
	MINE-POWER	0.80%	0.66%	0.92%
	MUNICIPAL-PUMP	0.25%	0.05%	0.03%
	OTHER-PUB-AUTH	3.79%	1.06%	0.90%
	PUBLIC-STREET	0.61%	0.05%	0.08%
	RESIDENTIAL	11.98%	12.41%	7.93%
Sep-07	COMMERCIAL-L-P	8.10%	9.41%	6.70%
	INDUSTRIAL-L-P	8.35%	4.66%	5.70%
	MINE-POWER	0.87%	0.80%	0.63%
	MUNICIPAL-PUMP	0.21%	0.07%	0.02%
	OTHER-PUB-AUTH	4.08%	1.11%	1.10%
	PUBLIC-STREET	0.57%	0.02%	0.03%
	RESIDENTIAL	12.21%	11.59%	7.13%

		A. 25c	A. 25d	A. 25e
		Payments as a % of Total Actual Bills for the Month		
Month	Rate Class	Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
Oct-07	COMMERCIAL-L-P	9.12%	11.48%	5.73%
	INDUSTRIAL-L-P	8.31%	6.51%	4.54%
	MINE-POWER	1.06%	0.87%	0.75%
	MUNICIPAL-PUMP	0.32%	0.02%	0.02%
	OTHER-PUB-AUTH	4.01%	1.29%	2.52%
	PUBLIC-STREET	0.73%	0.04%	0.03%
	RESIDENTIAL	12.36%	11.41%	6.46%
Nov-07	COMMERCIAL-L-P	6.95%	9.94%	7.66%
	INDUSTRIAL-L-P	9.16%	6.70%	7.06%
	MINE-POWER	1.15%	0.52%	1.51%
	MUNICIPAL-PUMP	0.30%	0.05%	0.05%
	OTHER-PUB-AUTH	3.57%	1.31%	1.09%
	PUBLIC-STREET	0.75%	0.09%	0.04%
	RESIDENTIAL	11.52%	11.35%	7.64%
Dec-07	COMMERCIAL-L-P	7.66%	8.70%	7.28%
	INDUSTRIAL-L-P	7.75%	4.99%	5.98%
	MINE-POWER	1.16%	0.41%	1.31%
	MUNICIPAL-PUMP	0.25%	0.05%	0.05%
	OTHER-PUB-AUTH	3.44%	1.05%	2.26%
	PUBLIC-STREET	0.68%	0.05%	0.05%
	RESIDENTIAL	12.06%	11.03%	10.79%
Jan-08	COMMERCIAL-L-P	8.69%	9.28%	5.06%
	INDUSTRIAL-L-P	5.67%	6.71%	2.95%
	MINE-POWER	1.26%	0.65%	0.45%
	MUNICIPAL-PUMP	0.29%	0.06%	0.03%
	OTHER-PUB-AUTH	3.55%	1.08%	0.60%
	PUBLIC-STREET	0.60%	0.04%	0.06%
	RESIDENTIAL	15.61%	14.33%	8.51%
Feb-08	COMMERCIAL-L-P	9.25%	9.12%	4.34%
	INDUSTRIAL-L-P	7.91%	5.43%	3.94%
	MINE-POWER	1.10%	1.11%	0.72%
	MUNICIPAL-PUMP	0.27%	0.06%	0.01%
	OTHER-PUB-AUTH	3.56%	1.08%	0.74%
	PUBLIC-STREET	0.60%	0.08%	0.03%
	RESIDENTIAL	16.28%	13.25%	7.61%

		A. 25c	A. 25d	A. 25e
		Payments as a % of Total Actual Bills for the Month		
Month	Rate Class	Received by the 10th day	Received between the 10th and 15th day	Received after the 15th day
Mar-08	COMMERCIAL-L-P	8.56%	10.04%	4.15%
	INDUSTRIAL-L-P	9.74%	5.02%	3.63%
	MINE-POWER	1.10%	1.16%	0.56%
	MUNICIPAL-PUMP	0.28%	0.07%	0.00%
	OTHER-PUB-AUTH	3.59%	0.94%	0.69%
	PUBLIC-STREET	0.66%	0.05%	0.03%
	RESIDENTIAL	15.90%	12.93%	7.56%
Apr-08	COMMERCIAL-L-P	10.08%	10.59%	4.03%
	INDUSTRIAL-L-P	10.14%	7.89%	2.64%
	MINE-POWER	1.29%	1.80%	0.46%
	MUNICIPAL-PUMP	0.31%	0.06%	0.04%
	OTHER-PUB-AUTH	3.75%	2.39%	0.62%
	PUBLIC-STREET	0.71%	0.09%	0.03%
	RESIDENTIAL	14.69%	11.79%	6.76%

KU Business Office Locations:

OFFICE	[illegible]	[illegible]
BARLOW	137 S. FOURTH STREET	42024
CAMPBELLSVILLE	109 W. MAIN STREET	42718
CARROLLTON	215 ELEVENTH STREET	41008
DANVILLE	198 W. BROADWAY	40422
EARLINGTON	111 W. MAIN STREET	42410
EDDYVILLE	219 W. MAIN STREET	42038
ELIZABETHTOWN	242 W. DIXIE AVENUE	42701
GEORGETOWN	204 W. CLINTON STREET	40324
GREENVILLE	380 AIRPORT ROAD	42345
HARLAN	184 BANK DRIVE	40831
LEXINGTON	ONE QUALITY STREET	40507
LEXINGTON NORTH	1620 N. LIMESTONE STREET	40505
LONDON	611 MEYERS BAKER ROAD	40741
MAYSVILLE	215 WALL STREET	41056
MIDDLESBORO	2201 CUMBERLAND AVENUE	40965
MOREHEAD	138 N. BLAIR AVENUE	40351
MORGANFIELD	110 N. MORGAN STREET	42437
MT. STERLING	209 W. LOCUST STREET	40353
PARIS	1445 S. MAIN STREET	40361
RICHMOND	200 E. WATER STREET	40475
SHELBYVILLE	1100 MAIN STREET	40065
SOMERSET	306 N. MAIN STREET	42501
VERSAILLES	250 CROSSFIELD DRIVE	40383
WINCHESTER	308 W. LEXINGTON STREET	40391

KU CheckFree Locations:

KU CheckFree Agent Name	KU CheckFree Agent Address	City	State	Zip
KEN'S NEW MARKET	304 SOUTH CHURCH STREET	CYNTHIANA	KY	41031
K'S BESTWAY, INC.	201 E. HRF BLVD.	AUGUSTA	KY	41002
PEG'S FOOD MART INC	1681 S. WILDERNESS RD.	MOUNT VERNON	KY	40456
PRICE LESS FOODS	1012 WINCHESTER ROAD	IRVINE	KY	40336
PARKVIEW IGA	1111 LINCOLN PARK ROAD	SPRINGFIELD	KY	40069
NOLIN RURAL ELECTRIC COOPERATIVE	101 WEST LINCOLN TRAIL	RADCLIFF	KY	40160
DURHAM'S GROCERY INC	606 LANCASTER STREET	STANFORD	KY	40484
SIZEMORE HARDWARE	RR1 BOX 1901A	PINEVILLE	KY	40977
CONRAD'S FOOD STORE	515 SOUTH MAIN ST.	MARION	KY	42064
KEN'S NEW MARKET	110 CLARK ST.	FLEMINGSBURG	KY	41041
D & M FAMILY FOODS	702 NORTH GREEN STREET	HENDERSON	KY	42420
VINE GROVE PIC PAC IGA	101 CRUTCHER STREET	VINE GROVE	KY	40175
MANCHESTER IGA # 1	414 MANCHESTER SQUARE	MANCHESTER	KY	40962
CITY OF SALEM	607 HOOK DR.	SALEM	KY	42078
S & K DRY CLEANERS	121 W. LEXINGTON ST.	HARRODSBURG	KY	40330
CASH A CHECK	1125 N. MAIN ST.	BEAVER DAM	KY	42320
SIZEMORE HARDWARE	302 KENTUCKY AVE	PINEVILLE	KY	40977
STEVE SHOPRITE	1565 E. MAIN ST.	HORSE CAVE	KY	42749
CHECK SWAP	401 U.S. HWY. 27 N.	WHITLEY CITY	KY	42653
CASH A CHECK	1004 BYPASS S.	LAWRENCEBURG	KY	40342
HIGDON'S FOODTOWN	507 W. MAIN ST.	LEBANON	KY	40033
CASH CONNECTION, INC.	1583 ELIZABETHTOWN RD.	LEITCHFIELD	KY	42754
CITY HALL	220 N. 5TH ST.	BARDSTOWN	KY	40004
EZ SHELL	181 HWY. 92 W.	WILLIAMSBURG	KY	40769
SAV-A STEP #43	3921 W. HWY. 146	LAGRANGE	KY	40031
FAMILY DRUG CENTER	501 W. FRONT ST.	COEBURN	VA	24230

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 26

Responding Witness: Butch Cockerill

Q-26. 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-26. The Company has not performed any such studies.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 27

Responding Witness: Butch Cockerill

Q-27. Refer to Volume 1 of 5 of KU's application, Tab 8, proposed P.S.C. 14 Original Sheet 102.

a. Provide a copy of all credit scoring services, public record financial information, financial scoring and modeling services and information provided by independent credit/financial watch services used by KU.

b. Given that the mailing of a late notice can affect a customer's credit score, how is KU ensuring that a customer's payment is not received the date the notice is mailed?

c. Will the mailing of a late payment notice be considered as a negative for the customer and used as a requirement for a new or recalculated deposit? If yes, how and when will the increased deposit be applied to a current customer that has a deposit on file?

A-27. a. Currently, KU uses only two services – Experian, one of the 3 major national credit bureaus, and Accurint, a product provided by LexisNexis. These services are used in the determination of residential service deposits.

b. The mailing of a late notice affects only the customer's **internal** behavioral score. Late notices are not reported to any external credit scoring service or provider. Nevertheless, all payments received are processed and posted to customer accounts before late notices are produced and mailed.

c. No, customer deposits are only assessed at the time of application for service, or following disconnect for nonpayment. Only if the customer goes off service and returns at a later date, would disconnect notices be used as a basis for requiring a deposit.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 28

Responding Witness: Butch Cockerill

Q-28. Refer to Volume 4 of 5 of KU's application, at SLC Exhibit 2, page 1 of 1, and SLC Exhibit 4, page 1 of 1. Explain why the average hourly rate for all employees is shown as $41.26 on Exhibit 2 and $54.69 on Exhibit 4.

A-28. The term "all employees" refers to the group of employees responsible for performing the work associated with the charge on each exhibit. The rate of $41.26 is the average hourly rate including overheads for Non-Exempt personnel responsible for meter data processing and employed in the Billing Integrity Department where as $54.69 is the average hourly rate including overheads for personnel responsible for meter testing and employed in the Meter Shop.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 29

Responding Witness: Butch Cockerill

Q-29. Refer to SLC Exhibit 3, page 1 of 1 of the Cockerill Testimony. Provide the cost support detail for the labor, transportation, supplies and equipment used to calculate the $12.22 cost per service order.

A-29. 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	$ 7.63	$ 7.63	$ 15.27
Outside Services	4.59	4.59	9.18
Total Costs	$ 12.22	$ 12.22	$ 24.45

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 30

Responding Witness: William Steven Seelye

Q-30. Refer to Volume 5 of 5 of KU's application, the Testimony of William S. Seelye ("Seelye Testimony"). Provide an electronic copy of the billing analysis and cost-of-service study with the formulas intact.

A-30. The requested information is being provided on CD.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 31

Responding Witness: William Steven Seelye

Q-31. Refer to pages 8-9 of the Seelye Testimony, which indicates that KU's residential customer charge is too low and that its residential energy charge is too high. KU is proposing to increase the customer charge from $5.00 to $8.49 and make no change to the energy charge. To what extent did KU consider a larger increase to the residential customer charge and a decrease, of some magnitude, to the residential energy charge?

A-31. 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 (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.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 32

Responding Witness: William Steven Seelye

Q-32. Refer to pages 16 and 17 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-32. See attached.

Customer Service: (800) 981-0600 Mon-Fri 7AM-7PM(EST)
Walk-in Center Hours: Mon-Fri 8AM-5PM(EST)
Telephone Payments: (800) 807-3596
www.eon-us.com

an e·on company

DATE DUE	AMOUNT DUE
08/15/08	$810,410.34

See the Billing Information section of this bill for important information regarding a possible problem with your meter(s)

ACCOUNT INFORMATION

Account Number:	111111-0111
Account Name:	John Q Public
Service Address:	123 Any Street Anywhere, KY 11111

BILLING SUMMARY

Previous Balance		623.017 54
Summary Transfer		(623,017.54)
Balance as of 08/05		0 00
Electric Charges	810,392.92	
Utility Charges as of 08/05		810.392 92
Other Charges		17.42
Total Amount Due		**810,410.34**

Averages for Billing Period	This Year	Last Year
Average Temperature	75 °	75 °
Number of Days Billed	31	30
Electric/kwh per Day	499458 0	442400 0

ELECTRIC CHARGES

Rate Type: LCI-TOD Transmission	
Customer Charge	120 00
Total Energy	508.158 62
Total On Peak (22.063 9 kw)	108.775 03
89 31% On Pk PF Adj to 90 00% ($4 93 x 170 5 kw)	840 57
Total Off Peak (22.068 0 kw)	28.026 36
88 99% Off Pk PF Adj to 90 00% ($1 27 x 250 5 kw)	318 14
Other Charges For Above Rates	
Fuel Adjustment ($ 00755 x 15483200 kwh)	116898 16
Environmental Surcharge (7 120% x $763.136 88)	54335 35
Merger Surcredit (0 866% CR x $817.472 23)	-7079.31
Total Electric Charges	**$810,392.92**

Please see reverse side for additional charges.

Bring entire bill when paying in person

Customer Service 1-800-383-5582

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number
111111-0111

Previous Balance	Payment Due Date	Total Amount Due	Winter Care Donation	Amount Enclosed
$0.00	8/15/2008	$810,410.34		$

Home Phone # (XXX) XXX-XXXX

☐Check here if plan(s) requested on back of stub

OFFICE USE ONLY: E
C01. R8851. G371

#BWNHBWG
#111111011 1 0#
John Q Public
123 Any Street
Anywhere, KY 11111

P O Box 536200
ATLANTA. GA 30353-6200

Service Address: Company Service Address

000000000000000000000000000000000000000000000000000

Attachment to Response to Question No. 32
Page 1 of 2
Cockerill

Sample: KU Transmission Customer Current kW bill

KU an e·on company

Customer Service: (800) 981-0600 Mon-Fri 7AM-7PM(EST)
Walk-in Center Hours: Mon-Fri 8AM-5PM(EST)
Telephone Payments: (800) 807-3596
www.eon-us com

DATE DUE	AMOUNT DUE
08/15/08	$810,942.31

ign up for our Demand Conservation program, and you will eceive $20 00 a year ($5 per month June through September)

Call 1-866-857-2665 today

ACCOUNT INFORMATION

Account Number:	111111-0111
Account Name:	John Q Public
Service Address:	123 Any Street Anywhere, KY 11111

BILLING SUMMARY

Previous Balance		623.017 54
Summary Transfer		(623,017.54)
Balance as of 08/05		0 00
Electric Charges	810,924.31	
Utility Charges as of 08/05		810.924 31
Other Charges		18.00
Total Amount Due		**810,942.31**

Averages for Billing Period	This Year	Last Year
Average Temperature	75 °	75 °
Number of Days Billed	31	30
Electric/kwh per Day	499458 0	442400.0

ELECTRIC CHARGES

Rate Type: Retail Transmission Service	
Customer Charge	120 00
Total Energy	503,513.66
Total On Peak ($4 39 x 24.708.7 kva)	108.471 19
Total Off Peak ($1 13 x 24.797.5 kva)	28,021 18
Other Charges For Above Rates	
Fuel Adjustment ($ 00755 x 15483200 kwh)	116898.16
Environmental Surcharge (7 120% x $757.024 19)	53900.12
Total Electric Charges	**$810,924.31**

Please see reverse side for additional charges

Bring entire bill when paying in person

Customer Service 1-800-383-5582

PLEASE RETURN THIS PORTION WITH YOUR PAYMENT

Account Number	Payment Due Date	Amount Due by Due Date	Amount Due 5 Days After Due Date	Winter Care Donation	Amount Enclosed
111111-0111	08/15/08	$810,942.31	$811,753.25		$

Home Phone # (XXX) XXX-XXXX

☐ Check here if plan(s) requested on back of stub

OFFICE USE ONLY: E
C01, R8851. G371

#BWNHBWG
#111111011 1 0#
John Q Public
123 Any Street
Anywhere, KY 11111

KU

P.O. Box 536200
ATLANTA, GA 30353-6200

ervice Address: Company Service Address

0000000000000000000000000000000000000000000000000

Attachment to Response to Question No. 32

Page 2 of 2

Cockerill

Sample: KU Transmission Customer Proposed kVa bill

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 33

Responding Witness: William Steven Seelye

Q-33. Refer to page 60 of the Seelye Testimony. Mr. Seelye states that allocation factors YECust05 and YECust06 were used to allocate meter reading, billing costs, and customer service expenses on the basis of a customer weighting factor based on discussions with LG&E's meter reading, billing and customer service departments.

a. Did Mr. Seelye intend to refer to KU's meter reading, billing and customer service departments rather than LG&E's?

b. Explain how these discussions were used to determine the allocation factors.

c. Provide examples of questions asked and how the answers were used to calculate the factors.

A-33. a. Yes.

b. Mr. Seelye relied on these discussions to establish the weighting factors which were multiplied by the number of customers served under each rate schedule to determine the allocation factors.

c. Mr. Seelye asked for the relative weights (with residential being equal to 1) of the cost of providing meter reading, billing and customer services to each rate class. The responses provided were the factors used.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 34

Responding Witness: William Steven Seelye

Q-34. Refer to page 66 of the Seelye Testimony. Table 1 shows that the Lighting rate class is earning an actual adjusted rate of return of 8.41 percent. Given that the proposed total Kentucky jurisdictional rate of return is 7.77 percent, explain why KU is proposing to increase rates for this rate class.

A-34. While the overall Lighting customer class is earning slightly more than the total return, Street Light Rate SL (which is the largest rate class within the lighting group) is earning a rate of return of only 4.51%. KU considered only increasing Rate SL and Decorative Street Lighting (which is also earning a rate of return below the overall return), but decided to increase all four lighting rates because of the somewhat higher equipment risk associated with providing lighting service.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 35

Responding Witness: William Steven Seelye

Q-35. Refer to Exhibit 4, of the Seelye Testimony. The first column on Page 1 shows miscellaneous service revenues of $6,158,810 and in the last column at an amount of $8,694,818. The difference, $2,536,008, is the amount of KU's proposed increased to miscellaneous service revenues. Explain why the $8,694,818 is the shown in column titled "Adjusted Billings at Current Rates" on page 1 and 2 and why $2,536,008 is shown as an increase to the $8,694,818 amount on page 2.

A-35. The $8,694,818 amount should not be shown on page 1 or page 2 of Seelye Exhibit 4. The $2,536,008 amount reflects the revenue impact of KU's proposed increase in miscellaneous charges. The $6,158,810 amount shown on page 1 represents KU's current miscellaneous revenue. Therefore, the $8,694,818 amount represents the level of miscellaneous revenues after taking into account the increase in miscellaneous revenue (i.e. $6,158,810 + $2,536,008 = $8,694,818). Although the $8,694,818 amount should not be shown on either page, it is appropriate to show the $2,536,008 on page 2 of the exhibit, and this amount should be included in the $22,109,840 total increase shown at the bottom of the page.

See attached for a revised Exhibit 4.

KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Revenue Adjusted to as Billed Basis	Adjustment to Remove ECR Billings	Adjustment to Remove DSM Billings	Adjustment to Remove Merger Surcredit Billings	Adjustment to Remove Value Delivery Surcredit	Adjustment to Reflect a Full Year of Base Rate Changes for FAC Rollin	Adjustment to Reflect FAC Billings for Full Year of the Rollin	Adjustment to Reflect Full Year of Base Rate Changes for ECR Rollin	Adjustment Reflecting Year-End Number of Customers	Adjustment Reflecting Customer Rate Switching during Test Year	Adjustment Reflecting Temperature Normalization	Adjusted Billings at Current Rates
Total Residential	419,658,185	(20,625,999)	(3,999,568)	6,931,759	1,281,117	26,969,802	(26,968,415)	8,317,267	843,080	-	(6,924,469)	405,482,758
General Service Rate GS - Secondary	136,859,057	(6,655,712)	(123,092)	2,258,368	416,427	8,173,074	(8,163,701)	2,660,581	1,130,662		(1,002,779)	135,552,885
General Service Rate GS - Primary	3,021,555	(150,004)	(2,670)	50,423	9,403	164,763	(198,343)	71,094	(40,127)			2,926,095
Total General Service	139,880,612	(6,805,716)	(125,762)	2,308,790	425,830	8,337,838	(8,362,043)	2,731,675	1,090,535	-	(1,002,779)	138,478,980
All Electric School Service Rate - AES	7,663,579	(375,761)	-	125,127	23,364	545,922	(545,878)	155,692	-			7,592,045
Large Power Rate LPS - Secondary	217,223,215	(10,481,169)	(240,135)	3,549,075	660,193	18,252,448	(18,201,574)	4,461,707	(6,373,654)		(565,554)	208,284,552
Large Power Rate LPP - Primary	83,319,658	(4,017,666)	(45,915)	1,260,029	253,206	7,774,251	(7,768,615)	1,608,542	-		(195,804)	82,187,686
Large Power Rate LPT - Transmission	1,313,122	(63,713)	(2,128)	21,533	3,988	118,293	(118,292)	25,729	-		-	1,298,531
Small Time-of-Day - STODS Secondary	9,082,582	(439,535)	(15,427)	149,681	27,621	889,347	(916,875)	150,385	-		(32,622)	8,895,156
Small Time-of-Day - STODP Primary	729,069	(35,498)	(215)	11,935	2,222	69,199	(71,871)	11,395	-		-	716,236
Small Time-of-Day - STODT Transmission	-	-	-	-		-	-	-	-			-
Total Combined Lighting & Power Service	311,667,645	(15,037,581)	(303,820)	4,992,254	947,229	27,103,538	(27,077,227)	6,257,758	(6,373,654)	-	(793,981)	301,382,162
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	129,809,288	(6,234,214)	-	1,535,989	394,429	12,980,212	(12,959,017)	2,520,001			-	128,046,688
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	39,511,303	(1,899,790)	-	460,770	120,177	3,739,483	(3,738,335)	772,635	-			38,966,242
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)	-	-	-		-	-	-	-	-	-	(96,313)
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)	-	-	-		-	-	-	-	-	-	(5,446,292)
Total Comm./Industrial Time-of-Day Service	163,777,986	(8,134,004)	-	1,996,759	514,605	16,719,695	(16,697,352)	3,292,636	-	-	-	161,470,325
Large Industrial Time of Day - LITOD	22,399,707	(1,074,397)	-	365,961	68,105	1,605,452	(1,605,452)	199,393	-			21,958,768
Coal Mining Power Service Rate - MP Primary	6,647,736	(322,307)	-	108,485	20,228	478,023	(451,324)	151,877	215,149			6,847,866
Coal Mining Power Service Rate - MP Transmission	3,858,666	(185,612)	-	63,911	11,701	316,330	(305,597)	80,508	-			3,839,906
Total Coal Mining Power Service	10,506,402	(507,920)	-	172,396	31,929	794,353	(756,922)	232,385	215,149	-	-	10,687,772
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,738,075	(226,784)	-	77,434	14,392	392,964	(392,865)	113,845	-			4,717,063
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	13,387,918	(653,513)	-	218,899	40,804	1,166,482	(1,169,016)	296,131	-			13,287,705
Total Large Mine Power Time-of-Day Service	18,125,994	(880,296)	-	296,333	55,196	1,559,446	(1,561,881)	409,976	-	-	-	18,004,768
Street Lighting - SL	7,312,070	(351,684)	-	120,138	22,193	192,583	(178,863)	131,336	5,438		-	7,253,212
Decorative Street Lighting - SLDEC	1,378,194	(62,946)	-	23,165	4,259	19,268	(14,694)	24,162	(87,075)			1,284,334
Private Outdoor Lighting - POL	4,076,501	(196,490)	-	66,864	12,408	142,318	(133,089)	74,198	65,957			4,108,667
Customer Outdoor Lighting - OL	6,015,216	(289,759)	-	98,990	19,315	214,873	(205,005)	109,176	(2,475)			5,960,330
Total Private Outdoor Lighting Service	18,781,981	(900,879)	-	309,157	58,175	569,042	(531,650)	338,872	(18,155)	-	-	18,606,543
TOTAL ULTIMATE CONSUMERS	$ 1,112,462,089	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,045)	$ -	$ (8,721,229)	$ 1,083,664,121
Miscellaneous Service Revenue	6,158,810											6,158,810
TOTAL JURISDICTIONAL	$ 1,118,620,900	$ (54,342,552)	$ (4,429,149)	$ 17,498,536	$ 3,405,550	$ 84,205,087	$ (84,106,820)	$ 21,935,653	$ (4,243,045)	$ -	$ (8,721,229)	$ 1,089,822,931

KENTUCKY UTILITIES COMPANY
Summary of Proposed Increase
Based on Sales for the 12 months ended April 30, 2008

	Adjusted Billings at Current Rates (see page 1)	Increase	Percentage Increase
Total Residential	405,482,758	17,329,356	4.27%
General Service Rate GS - Secondary	135,552,885		
General Service Rate GS - Primary	2,926,095	446,784	15.27%
Total General Service	138,478,980	446,784	0.32%
All Electric School Service Rate - AES	7,592,045	321,938	4.24%
Large Power Rate LPS - Secondary	208,284,552		
Large Power Rate LPP - Primary	82,187,686		
Large Power Rate LPT - Transmission	1,298,531	(70,621)	
Small Time-of-Day - STODS Secondary	8,895,156	82,070	0.92%
Small Time-of-Day - STODP Primary	716,236	6,637	0.93%
Small Time-of-Day - STODT Transmission	-		
Total Combined Lighting & Power Service	301,382,162	18,086	0.01%
Large Comm./Industrial Time-of-Day - LCI-TOD Primary	128,046,688		
Large Comm./Industrial Time-of-Day - LCI-TOD Transmission	38,966,242	(38,022)	
Curtailable Service Riders - Primary - LCI -TOD Primary	(96,313)		
Curtailable Service Riders - Transmission -LCI-TOD Transmission	(5,446,292)		
Total Comm./Industrial Time-of-Day Service	161,470,325	(38,022)	
Large Industrial Time of Day - LITOD	21,958,768		
Coal Mining Power Service Rate - MP Primary	6,847,866	575,463	8.40%
Coal Mining Power Service Rate - MP Transmission	3,839,906	100,123	2.61%
Total Coal Mining Power Service	10,687,772	675,586	6.32%
Large Mine Power Time-of-Day Rate - LMP-TOD Primary	4,717,063	29,196	0.62%
Large Mine Power Time-of-Day Rate - LMP-TOD Transmission	13,287,705	5,099	0.04%
Total Large Mine Power Time-of-Day Service	18,004,768	34,295	0.19%
Street Lighting - SL	7,253,212	304,645	4.20%
Decorative Street Lighting - SLDEC	1,284,334	61,720	4.81%
Private Outdoor Lighting - POL	4,108,667	195,020	4.75%
Customer Outdoor Lighting - OL	5,960,330	224,423	3.77%
Total Private Outdoor Lighting Service	18,606,543	785,809	4.22%
TOTAL ULTIMATE CONSUMERS	$ 1,083,664,121	19,573,832	1.81%
Miscellaneous Service Revenue	6,158,810	2,536,008	
TOTAL JURISDICTIONAL	1,089,822,931	22,109,840	2.03%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 36

Responding Witness: William Steven Seelye

Q-36. Refer to Exhibit 5, page 4 of 23 of the Seelye Testimony. This schedule shows a 15.27 percent increase for the current GS customers receiving primary service if they are shifted to rate PS as proposed by KU. Do these customers have the option of staying under the GS rate schedule? If no, explain why not.

A-36. Yes, if they convert their facilities at their cost to secondary service. Primary service customers are more suitably served under a rate that includes a demand charge.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 37

Responding Witness: William Steven Seelye

Q-37. Refer to Exhibit 5, page 5 of 23, of the Seelye Testimony. Explain the purpose of the "(335,544)" included in column 6.

A-37. The (335,544) is an amount that was inadvertently copied into the cell of the spreadsheet. It is not used in the calculation of the rate, nor does it affect any other number in the spreadsheet.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 38

Responding Witness: William Steven Seelye

Q-38. Refer to Exhibit 5, pages 12 and 13 of the Seelye Testimony.

a. Explain why the proposed rates do not include an energy rate.

b. Explain why the proposed increases do not reconcile to the increase shown for the STOD rate classes at Exhibit 4, page 2 of 2, of the Seelye Testimony.

A-38. a. The energy charge was inadvertently omitted in printing this exhibit. The proposed energy charge for Rate TOD is $0.03282 per kWh as shown on Sheet No. 21 of KU's proposed tariff included in Tab 7 of its *Statutory Notice, Application, Financial Exhibit, Table of Contents, Filing Requirements*. See response to Question No. 2(b).

b. The proposed increases shown on Exhibit 5, pages 12 and 13, do not reconcile to the increases shown for the STOD rate classes at Seelye Exhibit 4, page 2 of 2, because of the omission reference in the response to part (a) of this question. The increases shown on Seelye Exhibit 4, page 2 of 2, are correct. See response to Question No. 2(b).

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 39

Responding Witness: William Steven Seelye

Q-39. Refer to Exhibit 5, page 18 of 23, of the Seelye Testimony. The proposed rates in column 6 appear to be for transmission service. State whether any customers are taking primary service under rate LI-TOD. and if so, why they are not included.

A-39. There is only one customer served under Rate LI-TOD and that customer takes transmission voltage service. Thus there are no primary voltage customers.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 40

Responding Witness: William Steven Seelye

Q-40. Refer to Exhibit 16, page 14 of 33, of the Seelye Testimony. Explain how the total on line 18 in the "Kentucky State Jurisdiction" column was calculated.

A-40. There is a number omitted on the output for line 12 (RESERVE FOR DEF TAXES) in the "Kentucky State Jurisdiction". An amount of $256,897,609 should appear on this line. The total amount is correct. See attached.

07-Sep-08
02:31 PM

KENTUCKY UTILITIES COMPANY
ELECTRIC COST OF SERVICE STUDY
JURISDICTIONAL SEPARATION

RATE BASE: END OF YEAR
ALLOCATION METHOD: AVG 12 CP

12 MONTHS ENDING APRIL 30, 2008

		ALLOC	TOTAL KENTUCKY UTILITIES (1)-1	KENTUCKY STATE JURISDICTION (2)	VIRGINIA STATE JURISDICTION (3)	FERC & TENNESSEE JURISDICTION (4)	TENNESSEE STATE JURISDICTION (5)	FERC JURISDICTION (6)	PRIMARY (7)	TRANSMISSION (8)
	SUMMARY OF RESULTS AFTER ADJUSTMENT									
	ELEMENTS OF RATE BASE									
1	PLANT IN SERVICE		3,917,180,938	3,419,830,881	236,784,053	260,566,004	190,116	260,375,888	81,107,330	179,268,557
2	LESS RESERVE FOR DEPRECIATION		1,972,362,645	1,707,655,598	129,206,308	135,500,739	180,111	135,320,628	42,062,307	93,258,320
3	NET PLANT IN SERVICE		1,944,818,293	1,712,175,283	107,577,745	125,065,265	10,005	125,055,260	39,045,023	86,010,237
4	CONST WORK IN PROGRESS		1,234,053,513	1,075,862,772	58,908,640	99,282,101	9,618	99,272,483	30,495,609	68,776,874
5	NET PLANT		3,178,871,807	2,788,038,055	166,486,385	224,347,367	19,623	224,327,744	69,540,633	154,787,111
	ADD:									
6	MATERIALS & SUPPLIES		33,124,214	28,544,182	2,061,777	2,518,255	1,102	2,517,152	776,286	1,740,866
7	FUEL INVENTORY		52,838,865	45,885,975	2,266,314	4,686,576	365	4,686,211	1,489,432	3,196,780
8	PREPAYMENTS		1,664,279	1,461,220	97,937	105,122	84	105,038	32,868	72,170
9	WORKING CASH		87,541,433	78,937,746	1,629,974	6,973,712	1,337	6,972,376	2,211,531	4,760,845
10	EMISSION ALLOWANCES		223,085	193,051	10,675	19,359	2	19,358	5,898	13,460
11	TOTAL ADDITIONS		175,391,876	155,022,174	6,066,677	14,303,025	2,890	14,300,135	4,516,014	9,784,120
	DEDUCT:									
12	RESERVE FOR DEF TAXES		293,644,797	256,897,609	16,389,171	20,358,017	15,118	20,342,898	6,340,662	14,002,236
13	RESERVE FOR ITC		58,094,348	49,714,508	2,933,193	5,446,648	445	5,446,202	1,659,430	3,786,772
14	CUSTOMER ADVANCES		2,420,052	2,405,862	14,190	-	-	-	-	-
15	CUSTOMER DEPOSITS		759,207	-	759,207	-	-	-	-	-
16	DEFERRED FUEL-VIRGINIA		58,053	-	58,053	-	-	-	-	-
17	OPEB UNFUNDED		4,735,141	-	4,735,141	0	-	0	-	-
18	TOTAL DEDUCTIONS		359,711,598	309,017,979	24,888,955	25,804,664	15,564	25,789,101	8,000,092	17,789,009
19	NET ORIGINAL COST RATE BASE		2,994,552,085	2,634,042,250	147,664,107	212,845,727	6,950	212,838,777	66,056,555	146,782,223
	DEVELOPMENT OF RETURN									
20	OPERATING REVENUES		1,306,033,927	1,154,156,041	57,657,006	94,220,880	2,961	94,217,920	29,722,275	64,495,645
	OPERATING EXPENSES									
21	OPERATION & MAINT EXPENSE		903,348,115	788,744,613	42,781,655	71,821,846	11,955	71,809,891	22,767,538	49,042,353
22	DEPRECIATION & AMORT EXP		124,356,219	108,757,794	7,371,432	8,226,993	5,568	8,221,425	2,561,576	5,659,849
23	REGULATORY CREDITS		(2,196,420)	(1,901,684)	(104,747)	(189,988)	(16)	(189,972)	(57,889)	(132,083)
24	TAXES OTHER THAN INC TAX		18,993,835	16,998,492	947,853	1,047,490	390	1,047,101	328,647	718,454
25	INCOME TAXES		71,242,332	66,273,491	1,209,512	3,759,329	(6,032)	3,765,361	1,160,059	2,605,303
26	GAIN DISPOSITION ALLOWANCES		(583,107)	(504,602)	(27,902)	(50,602)	(4)	(50,598)	(15,415)	(35,183)
27	ACCRETION EXPENSE		1,901,344	1,646,311	90,636	164,397	14	164,383	50,093	114,290
28	TOTAL OPERATING EXPENSES		1,117,062,318	980,014,414	52,268,439	84,779,465	11,874	84,767,592	26,794,608	57,972,984
29	RETURN		188,971,609	174,141,627	5,388,567	9,441,415	(8,913)	9,450,328	2,927,667	6,522,661

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 41

Responding Witness: William Steven Seelye

Q-41. Refer to pages 56-57 of the Seelye Testimony and Seelye Exhibit 17.

a. Explain how the minimum system demand figure was calculated or whether it is simply the low point on the system load curve.

b. Explain how the winter and summer peak hours are calculated.

A-41. a. It is the low point on the combined system load curve.

b. The winter and summer peak hours are calculated by counting the number of hours in the summer and winter peak periods, respectively, as defined in the time of day tariffs. The summer peak period is defined as weekdays from 10:00 a.m. to 9:00 p.m., Eastern Standard Time. The winter peak period is defined as weekdays from 8:00 a.m. to 10:00 p.m., Eastern Standard Time.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 42

Responding Witness: William Steven Seelye

Q-42. Refer to pages 58-60 of the Seelye Testimony and Seelye Exhibit 18 pages 49-52.

a. Explain and define the functional vectors PROFIX and PROVAR.

b. For each of the functional vector allocators, internally generated or otherwise, listed in the Exhibit, provide an explanation of how they were derived and the locations of the calculations inside the cost of service study.

A-42. a. PROFIX is used to classify production operation and maintenance expenses as fixed (demand-related), and PROVAR is used to classify production operation and maintenance expenses as variable (energy). As in its prior cost of service studies, the Company classified production operation and maintenance expenses as fixed and variable using the FERC predominance methodology. Under the FERC predominance methodology, production operation and maintenance accounts that are predominately fixed, i.e. expenses that the FERC has determined to be predominately incurred independently of kilowatt hour levels of output are classified as demand-related. Production operation and maintenance accounts that are predominately variable, i.e., expenses that the FERC has determined to vary predominately with output (kWh) are considered to be energy related. The predominance methodology has been accepted in FERC proceedings for over 25 years and is a standard methodology for classifying production operation and maintenance expenses. For example, see *Public Service Company of New Mexico* (1980) 10 FERC ¶ 63,020, *Illinois Power Company* (1980), 11 FERC ¶ 63,040, *Delmarva Power & Light Company* (1981) 17 FERC ¶ 63,044, and *Ohio Edison Company* (1983) 24 FERC ¶ 63,068.

b. The internally- and externally-generated functional vector allocators are shown on pages 49 through 52 of Seelye Exhibit 18. The column labeled "Name" gives the name of the functional vector. Whenever, a particular vector name appears in the column labeled "Functional Vector" then that item is functionally assigned using that vector. Therefore, the internally generated functional vectors shown on pages 49 through 52 of Seelye Exhibit 18 are determined based on the item indicated in the column labeled "Function Vector", where such item is calculated on earlier pages of the spreadsheet model. For example, whenever a cost is functionally assigned on the basis of "PT&D" (which refers to Total Production, Transmission, and Distribution Plant"), then that particular cost is allocated on the basis of the Total Prod, Transmission, and Dist Plant identified with in the "Name" column as "PT&D" on page 1 of Seelye Exhibit 18. The Intangible Plant items shown toward the top of Page 1 of Seelye Exhibit 18 are functionally assigned on the basis the PT&D amounts shown on the bottom of the page.

The Company is in the process of compiling the requested information which requires extensive analysis. KU will supplement this response when the requested information is compiled and available. In the interim, the requested information can be traced using the electronic version of the cost of service study provided in response to Question No. 30.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 43

Responding Witness: William Steven Seelye

Q-43. Refer to the Seelye Testimony, at page 65, and Seelye Exhibits 18 (pages 49 - 50), 20, 21 and 22.

a. Explain how the weights for the zero intercept calculations were derived.

b. Explain the rationale for and how the results of the zero intercept calculations being split between the Distribution Primary and Distribution Secondary Lines.

c. Explain why the numbers in Exhibit 18 pages 49 and 50 for Underground Conductors and Devices and for Line Transformers do not sum to the results of the zero intercept calculations in Exhibits 21 and 22. Also, explain how this may change the results of the cost of service study?

d. Page 2 in Exhibits 20-22 appears to illustrate unweighted size and cost data, yet the results of the zero intercept calculations are based upon weighted data. Provide an explanation of and the calculations supporting the zero intercept and zero intercept cost on page 1 in each of the Exhibits.

e. Page 4 of Exhibits 20-22 show an estimated Y value. Explain how this was derived and show how it was used in the zero intercept calculations.

A-43. a. The weights for Exhibit 20 represent the Quantity in feet of overhead conductor installed by the Company by type of conductor. The weights for Exhibit 21 represent the Quantity in feet of underground conductor installed by the Company by type of conductor. The weights for Exhibit 22 represent the Quantity (or number) of line transformers by type of transformer.

b. Overhead conductor and underground conductor are split between primary and transmission voltage based on an engineering analysis. The Company's electric distribution engineering section apportioned each conductor type based on the amount installed at primary voltages and the amount installed at secondary voltages.

c. The numbers on Exhibit 18, pages 49 and 50, are separated between primary and secondary voltages. In total, line transformers sum to the results on Exhibit 22. The demand and customer allocations for overhead conductors were inadvertently applied to underground conductors. See attached for overhead and underground conductor splits between primary and secondary voltages.

d. The analysis does utilize weighted least squares. Weighted least squares is carried out by performing least squares regression (*without intercept*) using the following transformed model:

$$y\sqrt{n} = a\sqrt{n} + bx\sqrt{n}$$

where a is the intercept, b is the slope of the transformed model, x is the independent variable, y is the dependent variable, n is the weight. The appropriateness of using this transformed model can be determined by minimizing the weighted sum of squared differences:

$$\sum_i n_i(y_i - \hat{y}_i)^2$$

by setting the two partial derivatives of this sum with respect to the model coefficients equal to zero and solving the resulting system of equations. See pages 103-105 of Samprit Chatterjee and Bertram Price, *Regression Analysis by Example* (John Wiley and Sons, 1977).

Unlike the LG&E zero intercepts provided in Case No. 2008-00252, the trendlines shown on page 2 of the exhibits for KU are correct.

e. Est y is calculated by applying the size coefficient from the weighted least squares model to the x-value and then adding the intercept. For overhead conductor, est y is calculated as follows:

est y = intercept + (x-value) x (size coefficient)

= 1.5561915 + (x-value) x 0.0024414

Est y is not used in the zero intercept analysis. Its sole purpose is to determine the trendline.

Kentucky Utilities
Functional Vector for Overhead Conductors -- F003

Classification	Zero Intercept Percentages	Pri-Sec Split Percentages Primary	Secondary	Total
		81.4827%	18.5173%	
Customer Related	78.9190%	64.3053%	14.6137%	78.9190%
Demand Related	21.0810%	17.1774%	3.9036%	21.0810%
Total		81.4827%	18.5173%	100.0000%

Kentucky Utilities
Functional Vector for Underground Conductors -- F004

Classification	Zero Intercept Percentages	Pri-Sec Split Percentages Primary	Secondary	Total
		50.9022%	49.0978%	
Customer Related	72.14%	36.7187%	35.4170%	72.1357%
Demand Related	27.86%	14.1836%	13.6808%	27.8643%
Total		50.9022%	49.0978%	100.0000%

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 44

Responding Witness: William Steven Seelye

Q-44. Refer to Seelye Exhibit 19. For each of the allocation vectors listed in the Exhibit, provide an explanation of how they were derived and the locations of data upon which the calculations are based inside the cost of service study.

A-44. The Company is in the process of compiling the requested information which requires extensive analysis. KU will supplement this response when the requested information is compiled and available. In the interim, the requested information can be traced using the electronic version of the cost of service study provided in response to Question No. 30.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 45

Responding Witness: William Steven Seelye

Q-45. Refer to Volume 1 of 4 of the response to Staff's first request, Item 8, at page 2 of 2. Paragraph (c) states that KU is eliminating rate GS. Explain this statement.

A-45. KU is proposing to eliminate the option of customers' taking primary service under Rate GS, not the entire rate schedule.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 46

Responding Witness: Shannon L. Charnas

Q-46. Refer to the response to Staff's first request, Item 12(a), at page 1 of 3. Explain the decrease in Other Electric Revenues of $8,852,478 from year-end April 30, 2007 to year-end April 30, 2008.

A-46. The decrease in the other electric revenues is attributable to lower MISO related revenue resulting from the exit from the MISO in September 2006.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 47

Responding Witness: Lonnie E. Bellar / Valerie L. Scott

Q-47. Refer to page 8 of the Stafferi Testimony.

a. The *following future commitments* by E.ON U.S. LLC are discussed:

$1.5 million to the University of Kentucky for research on reducing carbon dioxide emissions;

$200,000 per year for 10 years to the Carbon Management Research Group;

$1.8 million over 2 years to the Kentucky Consortium of Carbon Storage; and

$25 million to the FutureGen Project.

b. For each of these commitments provide separately:

(1) The amount of contributions included in KU's test year operating expenses.

(2) A schedule showing the dates and amounts of the anticipated contributions.

(3) The amount of the contribution to be allocated to KU with an explanation for how the allocation between KU and LG&E was determined.

c. Also discussed on page 8 is a 3-year partnership between E.ON U.S. LLC and the University of Kentucky's Center for Applied Energy Research. With regard to this partnership respond to the following:

(1) Provide the total anticipated costs to E.ON U.S. LLC.

(2) State the costs of this partnership that is included in KU's test year operating expenses.

(3) Will the costs to E.ON U.S. LLC be entirely through cash contributions or is it E.ON U.S. LLC's intention to dedicate other resources to the partnership?

(4) If other resources will be dedicated to the project, provide a discussion of those resources, the amount of the anticipated costs of those resources, state when they are expected to occur, and how those costs will be allocated to KU and LG&E.

(5) Provide a schedule showing the anticipated dates and amounts of E.ON U.S. LLC's cash contributions to this partnership and discuss how they will be allocated to KU and LG&E.

d. Discuss, in complete detail, the process used by E.ON U.S. LLC and its subsidiaries when determining whether a research project, such as those referred to in a. and b., warrants their involvement and contribution.

e. Once the decision is made to participate or contribute to such a project, discuss the process used by E.ON U.S. LLC and its subsidiaries to determine the appropriate amount to be contributed.

f. Does E.ON U.S. LLC intend to eventually pass through the entire cost of the projects listed in (a) and (b) to the customers of KU and LG&E?

g. Provide a list of contributions made for research and development in the last 5 years by E.ON U.S. LLC and any of its subsidiaries or affiliates in support of clean air electric generation technologies that were ultimately paid for by stockholders and not included in rates.

A-47. a. and b.

University of Kentucky Research Foundation contributions				
Date	KU	LG&E	Annual Total	Comments
2006	$750,000	$750,000	$1,500,000	Recorded accrual to Acct. 426, split 50/50 as both companies share equally in benefit
10/06	($250,000)	($250,000)	($250,000)	1st payment
7/07	($250,000)	($250,000)	($250,000)	2nd payment
Late 2008	($250,000)	($250,000)	($250,000)	3rd payment to be made
Test Year	$0	$0	$0	Operating expenses

Carbon Management Research Group contributions				
Date	KU	LG&E	Annual Total	Comments
Test Year	$ 0	$ 0	$ 0	No contributions or expenses in the test year
2008	100,000	100,000	200,000	All anticipated payments to be split 50/50 as both Companies share equally in benefit. See below for account to be charged.
2009	100,000	100,000	200,000	
2010	100,000	100,000	200,000	
2011	100,000	100,000	200,000	
2012	100,000	100,000	200,000	
2013	100,000	100,000	200,000	
2014	100,000	100,000	200,000	
2015	100,000	100,000	200,000	
2016	100,000	100,000	200,000	
2017	100,000	100,000	200,000	
Total	$1,000,000	$1,000,000	$2,000,000	

Kentucky Consortium of Carbon Storage contributions				
Date	KU	LG&E	Annual Total	Comments
Test Year	$ 0	$ 0	$ 0	No contributions or expenses in the test year
2008	121,221	115,446	236,667	All anticipated payments to be split 51.22% to LG&E, 48.78% to KU, an allocation based on revenue, total assets and payroll costs from 12/07. See below for account to be charged.
2009	800,739	762,594	1,563,333	
Total	$921,960	$878,040	$1,800,000	

FutureGen contributions				
Date	KU	LG&E	Annual Total	Comments
9/06	$ 150,000	$ 150,000	$ 3 00,000	Charged to Acct 426
12/06	400,000	400,000	800,000	Charged to Acct 426
Test Year	0	0	0	No contributions or expenses in the test year
2009	1,050,000	1,050,000	2,100,000	All anticipated payments to be charged to Account 426 as paid, split 50/50 as both Companies share equally in benefit
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	

Pending the outcome of the Commission's Case No. 2008-00308, *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*, the contributions for Carbon Management Research Group and Kentucky Consortium of Carbon Storage will be charged to FERC Account No. 426 as paid. In this Case, the Company requests to defer the cost of these contributions as a regulatory asset for which it will seek rate recovery of in its next general rate application.

c. (1) See (a)-(b) above for the University of Kentucky Research Foundation. It is the same program as was listed for the University of Kentucky $1.5 million commitment.

(2) See (a)-(b) above for the University of Kentucky Research Foundation.

(3) The cost to the Company will be covered entirely under the cash contribution.

(4) Not applicable.

(5) See (a)-(b) above for the University of Kentucky Research Foundation.

d. and e. The Companies utilize the basic framework outlined below to determine their participation and the level of financial support to be provided.

<u>Need</u>: Is there a need within the Companies for the results of the research activities? Are the results of the research likely to support the Companies strategic initiatives?

Risk & Impact: Will the research help mitigate risks facing the Companies? Will the participation provide direct and timely benefits for customers?

Research Competence: Is the researcher competent in their field and are they likely to be successful?

Goals and Scope of Work: Are the research goals clearly defined and detailed with a scope of work including a timeline?

Funding Level: What is the assessment of the likely benefits of the research effort against the proposed cost? How does the cost/benefit analysis compare to other current research opportunities?

f. The $1.5m contribution to the University of Kentucky was recorded below-the-line and the Companies do not plan to seek recovery from customers.

The Companies' proposal for cost recovery is outlined in Case No. 2008-00308 for their proposed contributions to the Carbon Management Research Group and the Kentucky Consortium of Carbon Storage.

The contributions to the FutureGen project to-date have been recorded below-the-line thus not charged to the customers. Given the recent developments with respect to the FutureGen project and its somewhat uncertain future the Companies have not made a final decision with respect to cost recovery of FutureGen contributions.

g.

Research and Development Contributions for Clean Air Electric Generation Technologies from 2003-2008 Paid by Stockholders and Not Included in Rates				
Date	KU	LG&E	Annual Total	Comments
2003	$ 0	$ 0	$ 0	No such contributions
2004	0	0	0	No such contributions
2005	0	0	0	No such contributions
2006	550,000	550,000	1,100,000	FutureGen
2006	750,000	750,000	1,500,000	UK Research Foundation
2008	0	0	0	No such contributions
Test Year	0	0	0	No such contributions
Total	$1,300,000	$1,300,000	$2,600,000	

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 48

Responding Witness: Paul W. Thompson / John J. Spanos

Q-48. Refer to Volume 4 of 5 of KU's Application, the Testimony of Paul W. Thompson ("Thompson Testimony"), at page 7.

a. Discuss fully the tightening of environmental constraints and its impact on the retirement dates of generating facilities. This discussion should specifically address anticipated EPA regulations and their impact on specific generating units.

b. Discuss how the uncertainty of the retirement dates of the generating units discussed in a. was accounted for in the depreciation study submitted by KU in Case No. 2007-00565.

A-48. a. The most anticipated addition to current environmental legislation is carbon or greenhouse gas legislation mandating reduction in carbon dioxide emissions. There has been significant and ongoing interest and activity in Congress during the last two years concerning carbon legislation. However, there remains a wide spectrum of proposals and corresponding uncertainty. Further legislative activity can be anticipated following elections in November 2008, but when new legislation or regulations will be enacted and how it would impact the Companies' existing generation cannot be accurately predicted at this time.

In addition, the decisions this year by the United States Court of Appeals for the D. C. Circuit striking down the Clean Air Mercury Rule (CAMR) and Clean Air Act Interstate Rule (CAIR) are likely to lead to new regulations that may impose further environmental constraints relating to mercury, sulfur dioxide and nitrogen oxides within the next two to three years.

Any potential carbon legislation if enacted is more likely to have a greater impact the older, smaller coal-fired units. To simulate this, the Companies included a sensitivity in the 2008 IRP that included the retirement of Green River 3 and 4 and Tyrone 3 (total of 234 MW). This sensitivity assumed the three units would be retired in December 2014 and resulted in accelerating the need for additional generation capacity and $250 million in additional present value of revenue requirements.

b. The retirement dates for generating units in the depreciation study incorporate many variables and uncertainties. These probable retirement dates are the midpoint of all the probabilities of factors that would cause the retirement of each generating unit.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 49

Responding Witness: Paul W. Thompson

Q-49. Refer to page 11 of the Thompson Testimony.

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

b. Provide the number of Transmission Line Loading Relief directives called on KU's system for each calendar year since the adoption of thermal based ratings and for the 3 calendar years prior to its adoption.

A-49. 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

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 50

Responding Witness: Paul W. Thompson

Q-50. Refer to page 16 of the Thompson Testimony.

a. What will be KU's portion of ownership in the FutureGen project.

b. State the anticipated dates of completion for the refurbishment of the Dix Dam facility.

c. State the anticipated dates of completion for renovation of the Ohio Falls hydroelectric units.

A-50. a. FutureGen is a non profit consortium with a 501 (c) (3) tax status, made up of a mix of public and private companies, including KU and LG&E. Neither KU or LG&E have any actual ownership in FutureGen.

b. The Dix Dam facility is made up of three generating units. Unit 3's renovation will be complete in 2009. Units 1 and 2 are targeted for completion in 2012.

c. Ohio Falls is made up of eight generating units. The renovation of two of the eight units is now complete. The remaining six units are targeted for completion between 2010 and 2015.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 51

Responding Witness: Paul W. Thompson

Q-51. Refer to page 17 of the Thompson Testimony, 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 KU expect to make a decision and/or selection for acquiring power from renewable resources?

A-51. The Companies continue to evaluate the proposals. KU and LG&E will inform the Commission in a timely manner once a decision is known.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 52

Responding Witness: Chris Hermann

Q-52. Refer to Volume 4 of 5 of KU's Application, the Testimony of Chris Hermann ("Hermann Testimony") at page 6. Provide KU's SAIDI, SAIFI and CAIDI measurements, on an annual basis for the years 2003 through 2007.

A-52. The Distribution Reliability report for Kentucky Utilities Company (KU) 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.

KU initiated the installation of a new Outage Management System (OMS) in November 2003 and completed the installation in April 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 2004 as compared to the previous year.

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

Distribution Operations System Reliability
Kentucky Utilities Company

Kentucky Utilities	SAIDI (minutes)	SAIFI	CAIDI (minutes)
2003	87.20	0.751	116.19
2004	95.66	0.923	103.61
2005	71.77	0.756	94.99
2006	76.40	0.761	100.37
2007	75.07	0.739	101.60

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 53

Responding Witness: Robert M. Conroy

Q-53. Refer to all the allocation factors shown on Volume 1 of 4 of KU's response to Staff's first request, Item 13 and Volume 4 of 5 of KU's Application at Exhibit 1, Allocators of the Rives Testimony.

a. Provide a description of each factor and explain why its use is reasonable in all instances it is applied throughout Item 13 and KU's Application.

b. Indicate where in Volume 3 of 4 of KU's response to Staff's first request, Item 40 each allocation factor is calculated.

c. Provide workpapers for the allocation factors which are not included in Volume 3 of 4 of KU's response to Staff's first request, Item 40.

A-53. a. Allocation Factors of the Rives Testimony:

ECR Operating Expense:
This allocator is developed to accurately remove ECR operating expenses from KU's revenue requirement. ECR expenses include operating and maintenance expenses, depreciation expense and property tax expense. All expenses are jurisdictionalized in each ECR monthly filing on the basis of revenues; however, because for rate making purposes, KU's expenses are jurisdictionalized through the Jurisdictional Separation Study (Seelye Exhibit 16), ECR expenses removed from the revenue requirement must be jurisdictionalized using the same methods that are used in developing the revenue requirement. This allocator is used only on Reference Schedules 1.05 and 1.06.

Energy:
The Energy allocator is the ratio of Kentucky retail energy use in kWh to total KU energy sales in kWh. The Energy allocator is used to jurisdictionalize fuel inventory, fuel accounts payable, off-system and intercompany sales, fuel expense, boiler operations and maintenance expense, purchased power expense and regulatory expense. The Energy allocator is appropriate because the level of expense incurred or revenue realized is directly related to the level of energy sales.

Depreciation:
Depreciation expense is allocated to jurisdictions based on the amount of plant in service allocated to each jurisdiction in which KU provides service. The depreciation allocator is the result of dividing the sum of jurisdictional depreciation expense by total company depreciation expense and is applied to the depreciation expense accounts 403011 through 403115.

Labor:
The labor allocator is based on direct labor charges. Company employees charge time to various expense accounts according to the work being performed; this direct labor is then allocated to the jurisdictions on the basis of the production, transmission or distribution plant balance, whichever is appropriate. Customer-related direct labor is allocated on the basis of non-labor charges in the various customer-related areas. Administrative and General direct labor is allocated on the basis of total non-A&G labor. The Labor allocator is the result of dividing the sum of all labor for each jurisdiction by total company labor. The Labor allocator is applied to A&G accounts, payroll clearing accounts, pension benefit accounts, employment taxes accrued, employment taxes payable, and other employment-related short term liabilities (i.e. workers compensation payable, unemployment insurance, etc.)

Distribution plant:
The distribution plant allocator is based on distribution plant allocated to each jurisdiction. The allocator is applied to Distribution Operations Supervision and Engineering expenses, miscellaneous distribution operations expenses, rent from distribution facilities, supervision and engineering of distribution maintenance expenses, and miscellaneous distribution maintenance expenses.

Retail Energy:
The retail energy allocator is the ratio of each jurisdiction's energy sales to total retail energy sales. Retail Energy is applied to advertising expense. This allocation is appropriate because the Company's advertising is directed at its retail customers.

Demand:
The demand allocator is the ratio of each jurisdiction's 12-CP to the total company 12-CP. 12-CP is the average of the monthly peaks in each jurisdiction, coincident to KU's monthly peaks. The demand allocator is applied to generation and transmission assets (with the exception of certain Virginia transmission assets that are directly assigned to the Virginia jurisdiction), to system dispatch operations expenses, and to the capacity component of purchased power (if any). The demand allocator is appropriate for these costs because generation and transmission assets are built to meet load requirements.

EXP9025:
This allocator is the result of allocating customer accounting expenses to each jurisdiction. The EXP9025 allocator is applied to labor charged to customer accounting expenses. The allocator is appropriate for the postage increase adjustment on Rives Exhibit 1, Reference Schedule 1.30 because the customer accounting function performs billing services.

Allocated Operating Expense:
This allocator is the sum of jurisdictional operations expense divided by total company operations expense. This allocator is only applied to the proposed adjustment for vehicle fuel expense, and is appropriate because vehicles are used in all areas of the Company's operations.

Net Plant:
Net Plant is the jurisdictional ratio of Plant in Service less Accumulated Depreciation to total company plant in service less total company accumulated depreciation. Net Plant is applied to property taxes, which is appropriate because KU pays property taxes on its year-end net plant in service balance.

Income Tax Expense:
This allocator is the ratio of federal and state income taxes allocated to each jurisdiction. The income tax allocation is the sum of calculated income taxes in the jurisdictional study plus a true-up adjustment to make total federal and state taxes equal total taxes on the income statement. The true-up adjustment is allocated on rate base, based on the relationship of taxable income to rate base. Income Tax Expense is applied to all tax lines on the Amended Attachment to PSC-1 Question No. 13.

b. Allocators in Item 13:
In general the allocators identified below are either calculated and displayed at the referenced page in Seelye Exhibit 16, or they are calculated for Item 13 by dividing Kentucky State Jurisdiction (column 2) by Total Kentucky Utilities (column 1) for the designated amounts.

Plant:
Page 16 of 33, Row 30. This allocator is applied to plant in service balances on Item 13.

Demand:
Page 7 of 33, Row 1. This allocator is applied to ARO assets, ARO accumulated depreciation, ARO and MISO exit fee regulatory assets, emission allowance inventory, key man life insurance, ARO liabilities, certain deferred credits, ARO regulatory liabilities, demand component of purchased power, dispatch expenses,

CWIP:
Page 18 of 33, Row 15. This allocator is applied to CWIP balances on Item 13.

Accum Depr:
Page 17 of 33, Row 25. This allocator is applied to accumulated depreciation balances on Item 13.

RateBase:
Page 10, Row 11 This allocator is applied to cash accounts, prepaid expenses, financing expenses, customer orders, long term debt accounts payable, intercompany accounts payable, state sales taxes payable, property taxes, accrued interest on long term debt, and interest expense.

Revenue:
Page 10 of 33, Row 4. This allocator is applied to revenues that cannot be directly assigned based on sources, and certain accounts receivable that are not customer specific.

Labor:
Page 9 of 33, Row 3. This allocator is applied to labor-related pension assets and liabilities, employment taxes (accrued, payable, and expense) miscellaneous withholdings on behalf of employees (i.e. DCAP, savings bonds, HCRA, etc.), deferred compensation, and administrative and general expenses.

Energy:
Page 8 of 33, Row 1: This allocator is applied to fuel inventory accounts, transmission accounts payable, energy component of off-system sales, operating and maintenance expenses charged to FERC accounts 501, 512, 513, 544, 547, and the energy component of purchased power.

M&S:
Allocator is calculated using 13-month average materials and supplies balances, and the plant allocation factors for the types of materials in inventory. The allocator is applied only to materials and supplies balances.

Stores:
Allocator is calculated using 13-month average of account 163 balances.

Accum Def Inc Tax:
Page 19 of 33, Row 15.

Income taxes:
Page 27 of 33, Row 16 plus Row 24

Depr Exp:
Page 24 of 33, Rows 1 – 24

Amort Exp:
Page 24 of 33, Rows 25 and 26

Regulatory Credits:
Page 25 of 33, Row 11

Plant:
Page 16 of 33, Row 30

Stmplt:
Page 15 of 33, Row 8. Used to allocate steam operating and maintenance expenses that are not allocated on energy.

Hydplt:
Page 15 of 33, Row 12. Used to allocate hydro operating and maintenance expenses that are not allocated on energy.

Othplt:
Page 15 of 33, Row 16. Used to allocate other production operating and maintenance expenses that are not allocated on energy.

Prodplt:
Page 15 of 33, Row 17. Used to allocate system control and dispatch expenses.

Tranplt:
Page 15 of 33, Row 23. Used to allocate transmission operating and maintenance expenses.

Plt3602:
Page 16 of 33, Rows 3 and 16. Used to allocate distribution substation operating expenses.

Plt3645:
Page 16 of 33, Rows 4 and 17. Used to allocate distribution poles and overhead conductor operating and maintenance expenses.

Plt3667:
Page 16 of 33, Rows 5 and 18. Used to allocate distribution underground conductor operating and maintenance expenses.

Plt373:
Page 16 of 33, Rows 12 and 25. Used to allocate street lighting operating and maintenance expenses.

Plt370:
Page 16 of 33, Rows 10 and 23. Used to allocate meter operating and maintenance expenses.

Plt371:
Page 16 of 33, Rows 11 and 24. Used to allocated operating and maintenance expenses incurred while servicing outdoor lighting installed on private property.

Distplt:
Page 16 of 33, Row 28. Used to allocate distribution labor expenses.

Labca:
Page 33 of 33, Row 6. Used to allocate customer accounting expenses.

Labsa:
Page 33 of 33, Row 14. Used to allocate sales expenses charged to FERC accounts 907 and 911.

Cust908:
Page 8 of 33, Row 14: Direct assigned based on total customers. Used to allocate expenses charged to FERC account 908 – customer assistance.

Cust909:
Page 8 of 33, Row 15: Direct assigned based on retail customers, Used to allocate expenses charged to FERC account 909 – customer information.

Cust913:
see Cust909

c. All allocators are contained in Seelye Exhibit 13.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 54

Responding Witness: Lonnie E. Bellar

Q-54. Refer to Volume 4 of 5 of KU's Application, the Testimony of Lonnie E. Bellar ("Bellar Testimony") at page 6 where an explanation is given for the unbilled revenue adjustment decreasing test year operating revenues by $6,878,000.

a. In his testimony, Mr. Bellar states that the Commission accepted removal of unbilled revenues in KU's previous rate case, Case No. 2003-00434. The unbilled revenue adjustment in that case increased test year revenues by $675,000. The proposed unbilled revenue adjustment in the case at bar decreases test year revenues by $6,878,000. The net difference in the unbilled revenue adjustments of the previous and current case is $7,553,000. Provide an explanation for such a significant swing in the unbilled revenue adjustments.

b. Explain in detail why an unbilled revenue adjustment is appropriate for rate-making purposes.

A-54. a. The increase in the unbilled revenue adjustment is the result of customers paying higher rates on increased sales volumes in the test period April 2008 compared to the test period September 2003, in Case No. 2003-00434.

b. The adjustment to remove unbilled revenues from operating revenues is appropriate for a number of reasons.

First, the Commission has approved this type of adjustment in LG&E's rate cases for at least the last two rate cases prior to this case.

Second, the adjustment provides a better match of test-year revenues and expenses, using as-billed revenues for rate-making purposes rather than the revenues recorded on an accrual basis for accounting purposes.

Third, unbilled revenues are _estimates_ that attempt to put revenue on a calendar month basis instead of a billing cycle basis. As a result, there are no class billing determinants associated with unbilled revenues. The only metered billing determinants available are associated with as-billed revenue. With a historical test year, rate case revenue, allocators, billing determinants, etc. should be based on known and measured metered information that is readily available and verifiable, and much more accurate than estimated unbilled revenues data.

Fourth, the billing determinants used to develop the proposed rates *do not* include units related to the unbilled revenues. In other words, the billing determinants used to determine proposed rates reflect as billed determinants, and do not include unbilled determinants. Consequently, if unbilled revenues *are not* removed from test-year operating revenues, then the billing units used to establish rates in the case would need to be revised to also reflect unbilled revenue.

Fifth, if unbilled revenues *are not* removed from operating revenues, all revenue adjustments would have to be re-determined on an unbilled basis and not an as-billed basis.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 55

Responding Witness: Shannon L. Charnas

Q-55. Explain the methods used to calculate and record unbilled revenues. This explanation shall include discussion of accruals and subsequent reversals to all accounts used to account for unbilled revenues.

A-55. The Company uses an output based methodology to calculate unbilled revenue. Unbilled revenue is based on the daily electric net output (in kWh), which is the daily total output (load) reduced for line loss, non-jurisdictional and Company usage.

An unbilled percentage is applied to each day's electric net output to determine the daily unbilled kWh. The unbilled percentage is calculated by dividing the number of billing cycles billed prior to a given day by the total number of cycles for the month (i.e., 20). For example, if 4 billing cycles have occurred by the 6th of the month the unbilled percentage for the 6^{th} would be 20% (i.e. 4 billing cycles / 20 total billing cycles) or 20% of the net kWh output for that day would be unbilled.

The daily unbilled kWh is allocated to the various revenue classes based on the cooling degree days (CDD) and/or heating degree days (HDD) for that day. The daily unbilled kWh allocated to each revenue class is totaled for the month and then priced. The rates and regulatory mechanisms applicable to the next month (i.e., when this unbilled usage will be billed) are used to price the total unbilled kWh for each revenue class and determine the unbilled billed revenue.

The unbilled revenue is then accrued in the current month and immediately reversed in the following month. The Company records unbilled revenue in the general ledger by revenue class and revenue component.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 56

Responding Witness: Shannon L. Charnas

Q-56. a. Does KU accrue unbilled revenues on a monthly basis?

b. If yes to (a), provide an analysis of all entries to all accounts affected by the accounting for unbilled revenues for each month of the test year and provide workpapers showing how the amounts were determined.

A-56. a. Yes, KU does accrue unbilled revenues on a monthly basis.

b. See attached and Acrobat files on the CD for the requested analysis. Additionally, please see the Company's response to Question No. 55 for how the amounts were determined.

Kentucky Utilities Company
Case No. 2008-00251
Electric Unbilled Revenues
For the Test Year Ending April 30, 2008

		May-07		Jun-07		Jul-07		Aug-07		Sep-07		Oct-07	
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal
Electric Unbilled - Kentucky Utilities - Dr (Cr)													
Residential Sales - Revenue DSM	440101	$ (128,740)	$ 118,834	$ (144,903)	$ 128,740	$ (160,090)	$ 144,903	$ (205,444)	$ 160,090	$ (156,646)	$ 205,444	$ (130,621)	$ 156,646
Commercial Sales - DSM	442201	(13,979)	11,863	(15,480)	13,979	(15,440)	15,480	(19,158)	15,440	(14,154)	19,158	(14,122)	14,154
Industrial Sales - DSM	442301	(282)	235	(292)	282	(274)	292	(330)	274	(653)	330	(263)	653
Mine Power Sales - DSM	442601	(199)	171	(193)	199	(169)	193	(185)	169	(169)	185	(173)	169
Street Lighting Sales- DSM	444101	(24)	19	(23)	24	(27)	23	(31)	27	(21)	31	(24)	21
Public Authority Sales - DSM	445101	(2,484)	1,982	(2,552)	2,484	(2,485)	2,552	(3,266)	2,485	(2,481)	3,266	(2,549)	2,481
Municipal Pumping Sales - DSM	445301	(237)	209	(252)	237	(249)	252	(301)	249	(216)	301	(239)	216
DSM Subtotal													
Residential Sales - Energy - Nonfuel	440102	(6,580,692)	6,061,180	(7,381,868)	6,580,692	(8,136,888)	7,381,868	(10,426,778)	8,136,888	(7,945,432)	10,426,778	(6,659,941)	7,945,432
Commercial Sales - Energy - Nonfuel	442202	(3,475,358)	2,960,958	(3,899,537)	3,475,358	(3,880,259)	3,899,537	(4,855,888)	3,880,259	(3,632,026)	4,855,888	(3,553,028)	3,632,026
Industrial Sales - Energy - Nonfuel	442302	(2,172,268)	1,795,266	(2,158,524)	2,172,268	(2,105,973)	2,158,524	(2,240,903)	2,105,973	(1,760,419)	2,240,903	(1,759,384)	1,760,419
Mine Power Sales - Energy - Nonfuel	442602	(309,861)	259,786	(277,215)	309,861	(272,467)	277,215	(288,899)	272,467	(227,165)	288,899	(278,591)	227,165
Street Lighting Sales - Energy - Nonfuel	444102	(314,207)	195,619	(232,463)	314,207	(216,009)	232,463	(266,635)	216,009	(178,629)	266,635	(217,758)	178,629
Public Authority Sales - Energy - Nonfuel	445102	(538,603)	498,745	(579,375)	538,603	(565,863)	579,375	(734,680)	565,863	(561,216)	734,680	(581,830)	561,216
Municipal Pumping Sales - Energy - Nonfuel	445302	(47,498)	41,583	(49,928)	47,498	(39,493)	49,928	(46,915)	39,493	(38,709)	46,915	(42,507)	38,709
Energy - Nonfuel Subtotal													
Residential Sales - Energy - Fuel	440103	(3,837,399)	3,541,175	(4,314,352)	3,837,399	(4,765,350)	4,314,352	(6,115,194)	4,765,350	(4,663,393)	6,115,194	(3,896,858)	4,663,393
Commercial Sales - Energy - Fuel	442203	(3,414,475)	2,877,900	(3,769,054)	3,414,475	(3,768,927)	3,769,054	(4,676,443)	3,768,927	(3,455,507)	4,676,443	(3,497,843)	3,455,507
Industrial Sales - Energy - Fuel	442303	(5,274,521)	4,402,155	(5,251,335)	5,274,521	(4,883,851)	5,251,335	(5,398,397)	4,883,851	(3,952,352)	5,398,397	(4,238,441)	3,952,352
Mine Power Sales - Energy - Fuel	442603	(502,347)	465,007	(496,773)	502,347	(393,639)	496,773	(525,896)	393,639	(373,168)	525,896	(447,776)	373,168
Street Lighting Sales - Energy - Fuel	444103	(28,544)	24,924	(25,394)	28,544	(25,955)	25,394	(34,263)	25,955	(24,562)	34,263	(33,304)	24,562
Public Authority Sales - Energy - Fuel	445103	(932,838)	740,037	(957,019)	932,838	(915,552)	957,019	(1,185,496)	915,552	(908,186)	1,185,496	(944,856)	908,186
Municipal Pumping Sales - Energy - Fuel	445303	(55,241)	48,725	(58,753)	55,241	(57,920)	58,753	(70,029)	57,920	(50,246)	70,029	(55,495)	50,246
Energy - Fuel Subtotal													
Residential Sales - FAC	440104	-	-	-	-	-	-	-	-	-	-	-	-
Commercial Sales - FAC	442204	(3,856)		(10,229)	3,856	(1,011)	10,229	-	1,011	(1,158)	-	-	1,158
Industrial Sales - FAC	442304	-		-	-	(30,980)	-	-	30,980	(36,842)	-	-	36,842
Mine Power Sales - FAC	442604	(4,754)		-	4,754	-	-	-	-	-	-	-	-
Street Lighting Sales - FAC	444104	-		-	-	-	-	-	-	-	-	-	-
Public Authority Sales - FAC	445104	-		(468)	-	(366)	468	-	366	-	-	-	-
Municipal Pumping Sales - FAC	445304	-		-	-	-	-	-	-	-	-	-	-
FAC Subtotal													
Commercial Sales - STOD PCR	442205	(6,904)	7,757	(7,577)	6,904	(7,442)	7,577	(9,163)	7,442	(6,756)	9,163	(6,994)	6,756
Industrial Sales - STOD PCR	442305	(5,927)	6,736	(6,208)	5,927	(5,768)	6,208	(6,391)	5,768	(5,149)	6,391	(5,079)	5,149
Mine Power Sales - STOD PCR	442605	(94)	110	(85)	94	(78)	85	(94)	78	(59)	94	(73)	59
Street Lighting Sales - STOD PCR	444105	(13)	13	(12)	13	(15)	12	(17)	15	(11)	17	(12)	11
Public Authority Sales - STOD PCR	445105	(1,637)	1,731	(1,675)	1,637	(1,620)	1,675	(2,139)	1,620	(1,627)	2,139	(1,681)	1,627
Municipal Pumping Sales - STOD PCR	445305	(140)	164	(150)	140	(153)	150	(184)	153	(133)	184	(147)	133
STOD PCR Subtotal													
Residential Sales - ECR	440111	(615,807)	370,483	(667,786)	615,807	(749,354)	667,786	(1,070,914)	749,354	(905,559)	1,070,914	(625,596)	905,559
Commercial Sales - ECR	442211	(529,221)	293,223	(559,262)	529,221	(563,845)	559,262	(785,248)	563,845	(644,558)	785,248	(535,701)	644,558
Industrial Sales - ECR	442311	(631,414)	333,921	(608,017)	631,414	(569,509)	608,017	(716,808)	569,509	(600,114)	716,808	(500,782)	600,114
Mine Power Sales - ECR	442611	(69,552)	39,952	(64,966)	69,552	(57,984)	64,966	(79,075)	57,984	(62,622)	79,075	(60,704)	62,622
Street Lighting Sales - ECR	444111	(16,301)	7,394	(12,539)	16,301	(12,600)	12,539	(17,230)	12,600	(12,201)	17,230	(12,853)	12,201
Public Authority Sales - ECR	445111	(125,625)	67,067	(124,401)	125,625	(119,789)	124,401	(177,307)	119,789	(149,403)	177,307	(127,759)	149,403
Municipal Pumping Sales - ECR	445311	(8,142)	4,659	(8,271)	8,142	(7,804)	8,271	(10,568)	7,804	(8,678)	10,568	(7,806)	8,678
ECR Subtotal													

Kentucky Utilities Company
Case No. 2008-00251
Electric Unbilled Revenues
For the Test Year Ending April 30, 2008

		Nov-07		Dec-07		Jan-08		Feb-08		Mar-08		Apr-08		Total
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	
Electric Unbilled - Kentucky Utilities - Dr (Cr)														
Residential Sales - Revenue DSM	440101	$ (136,784)	$ 130,621	$ (175,802)	$ 136,784	$ (205,984)	$ 175,802	$ (185,997)	$ 205,984	$ (146,333)	$ 185,997	$ (125,133)	$ 146,333	$ (6,299)
Commercial Sales - DSM	442201	(14,720)	14,122	(13,898)	14,720	(14,228)	13,898	(13,121)	14,228	(12,643)	13,121	(12,661)	12,643	(798)
Industrial Sales - DSM	442301	(63)	263	(67)	63	(306)	67	(298)	306	(276)	298	(144)	276	91
Mine Power Sales - DSM	442601	(219)	173	(213)	219	(207)	213	(187)	207	(186)	187	(102)	186	69
Street Lighting Sales- DSM	444101	(25)	24	(29)	25	(33)	29	(34)	33	(30)	34	(29)	30	(10)
Public Authority Sales - DSM	445101	(2,486)	2,549	(2,414)	2,486	(3,259)	2,414	(2,978)	3,259	(3,040)	2,978	(2,987)	3,040	(1,005)
Municipal Pumping Sales - DSM	445301	(261)	239	(267)	261	(259)	267	(240)	259	(236)	240	(254)	236	(45)
DSM Subtotal														(7,998)
Residential Sales - Energy - Nonfuel	440102	(8,748,117)	6,659,941	(8,924,102)	8,748,117	(10,424,263)	8,924,102	(9,420,957)	10,424,263	(7,420,327)	9,420,957	(5,912,598)	7,420,327	148,582
Commercial Sales - Energy - Nonfuel	442202	(5,345,008)	3,553,028	(3,766,924)	5,345,008	(3,883,716)	3,766,924	(3,667,781)	3,883,716	(3,491,076)	3,667,781	(3,279,134)	3,491,076	(318,176)
Industrial Sales - Energy - Nonfuel	442302	(4,364,599)	1,759,384	(2,015,992)	4,364,599	(1,929,766)	2,015,992	(1,880,635)	1,929,766	(1,823,124)	1,880,635	(1,764,517)	1,823,124	30,749
Mine Power Sales - Energy - Nonfuel	442602	(549,036)	278,591	(300,966)	549,036	(312,764)	300,966	(300,748)	312,764	(286,201)	300,748	(276,496)	286,201	(16,710)
Street Lighting Sales - Energy - Nonfuel	444102	(266,029)	217,758	(226,306)	266,029	(261,400)	226,306	(295,558)	261,400	(265,557)	295,558	(283,132)	265,557	(87,513)
Public Authority Sales - Energy - Nonfuel	445102	(971,165)	581,830	(576,598)	971,165	(802,964)	576,598	(738,510)	802,964	(736,281)	738,510	(620,942)	736,281	(122,196)
Municipal Pumping Sales - Energy - Nonfuel	445302	(74,073)	42,507	(50,636)	74,073	(50,873)	50,636	(48,135)	50,873	(46,872)	48,135	(42,506)	46,872	(922)
Energy - Nonfuel Subtotal														(366,188)
Residential Sales - Energy - Fuel	440103	(4,083,686)	3,896,858	(7,503,018)	4,083,686	(8,781,003)	7,503,018	(7,925,014)	8,781,003	(6,237,988)	7,925,014	(4,717,693)	6,237,988	(1,176,518)
Commercial Sales - Energy - Fuel	442203	(3,634,136)	3,497,843	(4,915,852)	3,634,136	(5,028,976)	4,915,852	(4,646,803)	5,028,976	(4,471,470)	4,646,803	(4,333,992)	4,471,470	(1,456,092)
Industrial Sales - Energy - Fuel	442303	(5,152,075)	4,236,441	(7,131,935)	5,152,075	(6,654,880)	7,131,935	(6,483,019)	6,654,880	(6,290,818)	6,483,019	(6,110,148)	6,290,818	(1,707,993)
Mine Power Sales - Energy - Fuel	442603	(564,829)	447,776	(761,676)	564,829	(808,573)	761,676	(798,831)	808,573	(742,425)	798,831	(692,497)	742,425	(227,489)
Street Lighting Sales - Energy - Fuel	444103	(39,331)	33,304	(57,080)	39,331	(64,360)	57,080	(60,785)	64,360	(54,851)	60,785	(49,229)	54,851	(24,305)
Public Authority Sales - Energy - Fuel	445103	(893,651)	944,856	(1,249,587)	893,651	(1,655,260)	1,249,587	(1,510,320)	1,655,260	(1,516,694)	1,510,320	(1,406,447)	1,516,694	(666,410)
Municipal Pumping Sales - Energy - Fuel	445303	(60,653)	55,495	(89,156)	60,653	(86,617)	89,156	(80,373)	86,617	(79,129)	80,373	(76,383)	79,129	(27,657)
Energy - Fuel Subtotal														(5,286,465)
Residential Sales - FAC	440104	(570,192)	-	(2,301,140)	570,192	(428,835)	2,301,140	31,925	428,835	(1,179,341)	(31,925)	(116,449)	1,179,341	(116,449)
Commercial Sales - FAC	442204	(511,644)	-	(1,486,635)	511,644	(243,196)	1,486,635	13,647	243,196	(846,022)	(13,647)	(104,871)	846,022	(104,871)
Industrial Sales - FAC	442304	(723,498)	-	(2,214,022)	723,498	(315,439)	2,214,022	17,343	315,439	(1,192,970)	(17,343)	(147,974)	1,192,970	(147,974)
Mine Power Sales - FAC	442604	(79,263)	-	(233,706)	79,263	(38,256)	233,706	3,261	38,256	(140,384)	(3,261)	(15,890)	140,384	(15,890)
Street Lighting Sales - FAC	444104	(5,519)	-	(17,511)	5,519	(3,132)	17,511	243	3,132	(10,373)	(243)	(1,198)	10,373	(1,198)
Public Authority Sales - FAC	445104	(125,397)	-	(388,914)	125,397	(72,535)	388,914	5,988	72,535	(286,964)	(5,988)	(20,968)	286,964	(20,968)
Municipal Pumping Sales - FAC	445304	(8,527)	-	(27,417)	8,527	(4,186)	27,417	309	4,186	(14,955)	(309)	(1,858)	14,955	(1,858)
FAC Subtotal														(409,208)
Commercial Sales - STOD PCR	442205	(7,041)	6,994	(6,365)	7,041	(6,433)	6,365	(5,879)	6,433	(5,737)	5,879	(5,819)	5,737	1,938
Industrial Sales - STOD PCR	442305	(6,248)	5,079	(5,753)	6,248	(5,141)	5,753	(5,061)	5,141	(4,747)	5,061	(4,556)	4,747	2,180
Mine Power Sales - STOD PCR	442605	(98)	73	(81)	98	(81)	81	(84)	81	(41)	84	(33)	41	77
Street Lighting Sales - STOD PCR	444105	(13)	12	(14)	13	(15)	14	(16)	15	(14)	16	(14)	14	(1)
Public Authority Sales - STOD PCR	445105	(1,628)	1,681	(1,552)	1,628	(2,076)	1,552	(1,900)	2,076	(1,937)	1,900	(1,655)	1,937	76
Municipal Pumping Sales - STOD PCR	445305	(157)	147	(158)	157	(152)	158	(138)	152	(138)	138	(136)	138	28
STOD PCR Subtotal														4,298
Residential Sales - ECR	440111	(895,537)	625,596	(1,431,413)	895,537	(1,098,476)	1,431,413	(607,536)	1,098,476	(851,611)	607,536	(433,749)	851,611	(63,266)
Commercial Sales - ECR	442211	(774,457)	535,701	(928,613)	774,457	(620,712)	928,613	(356,972)	620,712	(603,690)	356,972	(384,641)	603,890	(91,418)
Industrial Sales - ECR	442311	(859,288)	500,782	(1,063,815)	859,288	(638,825)	1,063,815	(377,593)	638,825	(653,032)	377,593	(407,516)	653,032	(73,595)
Mine Power Sales - ECR	442611	(104,023)	60,704	(126,275)	104,023	(85,099)	126,275	(51,440)	85,099	(86,379)	51,440	(52,021)	86,379	(12,069)
Street Lighting Sales - ECR	444111	(19,667)	12,853	(22,199)	19,667	(17,925)	22,199	(12,083)	17,925	(18,142)	12,083	(12,537)	18,142	(5,143)
Public Authority Sales - ECR	445111	(171,604)	127,759	(211,098)	171,604	(179,422)	211,098	(101,169)	179,422	(179,669)	101,169	(107,653)	179,669	(40,586)
Municipal Pumping Sales - ECR	445311	(12,198)	7,806	(15,583)	12,198	(9,837)	15,583	(5,754)	9,837	(9,816)	5,754	(6,174)	9,816	(1,515)
ECR Subtotal														(287,592)

Kentucky Utilities Company
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		May-07		Jun-07		Jul-07		Aug-07		Sep-07		Oct-07	
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal
Residential Sales - MSR	440112	193,747	(163,384)	372,853	(193,747)	256,912	(372,853)	339,917	(256,912)	285,375	(339,917)	222,804	(285,375)
Commercial Sales - MSR	442212	166,739	(129,312)	311,793	(166,739)	193,394	(311,793)	249,244	(193,394)	203,125	(249,244)	190,788	(203,125)
Industrial Sales - MSR	442312	198,658	(147,260)	339,481	(198,658)	196,758	(339,481)	227,521	(196,758)	189,144	(227,521)	178,352	(189,144)
Mine Power Sales - MSR	442612	22,203	(17,619)	36,273	(22,203)	19,879	(36,273)	25,099	(19,879)	19,735	(25,099)	21,620	(19,735)
Street Lighting Sales - MSR	444112	5,129	(3,261)	7,001	(5,129)	4,320	(7,001)	5,469	(4,320)	3,845	(5,469)	4,578	(3,845)
Public Authority Sales - MSR	445112	39,525	(29,577)	69,486	(39,525)	41,099	(69,486)	56,279	(41,099)	47,082	(56,279)	45,501	(47,082)
Municipal Pumping Sales - MSR	445312	2,562	(2,055)	4,618	(2,562)	2,676	(4,618)	3,354	(2,676)	2,735	(3,354)	2,780	(2,735)
MSR Subtotal													
Residential Sales - VDT	440114	43,253	(36,474)	45,703	(43,253)	47,734	(45,703)	63,156	(47,734)	53,022	(63,156)	41,397	(53,022)
Commercial Sales - VDT	442214	37,223	(28,868)	38,288	(37,223)	35,919	(38,288)	46,309	(35,919)	37,740	(46,309)	35,448	(37,740)
Industrial Sales - VDT	442314	44,349	(32,875)	41,612	(44,349)	36,311	(41,612)	42,273	(36,311)	35,143	(42,273)	33,137	(35,143)
Mine Power Sales - VDT	442614	4,957	(3,933)	4,446	(4,957)	3,694	(4,446)	4,663	(3,694)	3,667	(4,663)	4,017	(3,667)
Street Lighting Sales - VDT	444114	1,145	(728)	858	(1,145)	803	(858)	1,016	(803)	714	(1,016)	850	(714)
Public Authority Sales - VDT	445114	8,824	(6,603)	8,527	(8,824)	7,631	(8,527)	10,456	(7,631)	8,748	(10,456)	8,454	(8,748)
Municipal Pumping Sales - VDT	445314	572	(459)	566	(572)	497	(566)	623	(497)	508	(623)	517	(508)
VDT Subtotal													
Commercial Sales - Demand Charge	442218	(2,356,709)	1,980,460	(2,374,295)	2,356,709	(2,246,983)	2,374,295	(2,772,296)	2,246,983	(1,979,878)	2,772,296	(2,277,984)	1,979,878
Industrial Sales - Demand Charge	442318	(3,618,366)	3,005,256	(3,628,459)	3,618,366	(3,334,650)	3,628,459	(3,734,321)	3,334,650	(2,735,034)	3,734,321	(2,979,650)	2,735,034
Mine Power Sales - Demand Charge	442618	(474,302)	398,861	(436,823)	474,302	(415,442)	436,823	(468,751)	415,442	(313,568)	468,751	(387,222)	313,568
Street Lighting Sales - Demand Charge	444118	(4,017)	3,357	(4,642)	4,017	(4,542)	4,642	(6,108)	4,542	(3,503)	6,108	(4,188)	3,503
Public Authority Sales - Demand Charge	445118	(728,155)	592,952	(709,784)	728,155	(654,521)	709,784	(882,117)	654,521	(630,585)	882,117	(742,669)	630,585
Municipal Pumping Sales - Demand Charge	445318	(43,717)	38,363	(43,918)	43,717	(42,527)	43,918	(50,745)	42,527	(35,404)	50,745	(41,782)	35,404
Demand Charge Subtotal													
Residential Sales - Customer Charge	440119	(1,086,362)	997,187	(1,020,646)	1,086,362	(1,050,964)	1,020,646	(1,105,743)	1,050,964	(1,005,367)	1,105,743	(1,124,185)	1,005,367
Commercial Sales - Customer Charge	442219	(672,460)	618,020	(632,135)	672,460	(647,405)	632,135	(679,358)	647,405	(617,826)	679,358	(690,564)	617,826
Industrial Sales - Customer Charge	442319	(32,228)	29,566	(30,258)	32,228	(31,065)	30,258	(32,643)	31,065	(29,724)	32,643	(32,891)	29,724
Mine Power Sales - Customer Charge	442619	(4,051)	3,665	(3,665)	4,051	(3,793)	3,665	(3,864)	3,793	(3,650)	3,864	(4,098)	3,650
Street Lighting Sales - Customer Charge	444119	(6,168)	5,663	(5,786)	6,168	(5,974)	5,786	(6,200)	5,974	(5,632)	6,200	(6,289)	5,632
Public Authority Sales - Customer Charge	445119	(77,006)	70,666	(72,250)	77,006	(73,534)	72,250	(77,730)	73,534	(70,333)	77,730	(78,611)	70,333
Municipal Pumping Sales - Customer Charge	445319	(4,159)	3,810	(3,912)	4,159	(4,027)	3,912	(4,234)	4,027	(3,857)	4,234	(4,322)	3,857
Customer Charge Subtotal													
Total Kentucky Utilities Unbilled	173001	$(37,988,000)	$ 32,325,000	$ (39,372,000)	$37,988,000	$(40,003,000)	$ 39,372,000	$ (48,719,000)	$40,003,000	$ (36,924,000)	$ 48,719,000	$ (35,825,000)	$ 36,924,000

Attachment to Response to PSC-2 Question No. 56(b)
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Charnas

Kentucky Utilities Company
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		Nov-07		Dec-07		Jan-08		Feb-08		Mar-08		Apr-08		Total
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	
Residential Sales - MSR	440112	247,128	(222,804)	341,305	(247,128)	348,665	(341,305)	303,081	(348,665)	268,374	(303,081)	191,672	(268,374)	28,288
Commercial Sales - MSR	442212	213,716	(190,788)	221,418	(213,716)	197,019	(221,418)	178,082	(197,019)	190,308	(178,082)	169,971	(190,308)	40,659
Industrial Sales - MSR	442312	237,125	(178,352)	253,655	(237,125)	202,768	(253,655)	188,369	(202,768)	205,794	(188,369)	180,079	(205,794)	32,820
Mine Power Sales - MSR	442612	28,706	(21,620)	30,109	(28,706)	27,011	(30,109)	25,662	(27,011)	27,221	(25,662)	22,988	(27,221)	5,369
Street Lighting Sales - MSR	444112	5,427	(4,578)	5,293	(5,427)	5,690	(5,293)	6,028	(5,690)	5,717	(6,028)	5,540	(5,717)	2,279
Public Authority Sales - MSR	445112	47,355	(45,501)	50,334	(47,355)	56,950	(50,334)	50,470	(56,950)	56,620	(50,470)	47,571	(56,620)	17,995
Municipal Pumping Sales - MSR	445312	3,366	(2,780)	3,716	(3,366)	3,122	(3,716)	2,870	(3,122)	3,093	(2,870)	2,728	(3,093)	674
MSR Subtotal														128,083
Residential Sales - VDT	440114	45,916	(41,397)	73,983	(45,916)	63,270	(73,983)	54,998	(63,270)	48,700	(54,998)	34,781	(48,700)	(1,693)
Commercial Sales - VDT	442214	39,708	(35,448)	47,995	(39,708)	35,752	(47,995)	32,315	(35,752)	34,534	(32,315)	30,843	(34,534)	1,975
Industrial Sales - VDT	442314	44,057	(33,137)	54,983	(44,057)	36,795	(54,983)	34,182	(36,795)	37,344	(34,182)	32,678	(37,344)	(197)
Mine Power Sales - VDT	442614	5,333	(4,017)	6,527	(5,333)	4,902	(6,527)	4,657	(4,902)	4,940	(4,657)	4,171	(4,940)	238
Street Lighting Sales - VDT	444114	1,008	(850)	1,147	(1,008)	1,032	(1,147)	1,094	(1,032)	1,037	(1,094)	1,005	(1,037)	277
Public Authority Sales - VDT	445114	8,798	(8,454)	10,911	(8,798)	10,334	(10,911)	9,158	(10,334)	10,274	(9,158)	8,632	(10,274)	2,030
Municipal Pumping Sales - VDT	445314	625	(517)	805	(625)	567	(805)	521	(567)	561	(521)	495	(561)	36
VDT Subtotal														2,666
Commercial Sales - Demand Charge	442218	(2,480,515)	2,277,984	(2,119,925)	2,480,515	(1,992,003)	2,119,925	(1,943,389)	1,992,003	(1,908,429)	1,943,389	(2,194,524)	1,908,429	(214,064)
Industrial Sales - Demand Charge	442318	(3,783,765)	2,979,650	(3,497,928)	3,783,765	(3,186,895)	3,497,928	(3,097,342)	3,186,895	(2,955,575)	3,097,342	(3,124,181)	2,955,575	(118,925)
Mine Power Sales - Demand Charge	442618	(504,481)	387,222	(467,682)	504,481	(451,168)	467,682	(463,802)	451,168	(453,779)	463,802	(437,331)	453,779	(38,470)
Street Lighting Sales - Demand Charge	444118	(4,608)	4,188	(3,983)	4,608	(5,256)	3,983	(5,539)	5,256	(4,999)	5,539	(4,761)	4,999	(1,404)
Public Authority Sales - Demand Charge	445118	(736,398)	742,669	(657,833)	736,398	(798,988)	657,833	(761,030)	798,988	(765,741)	761,030	(830,286)	765,741	(237,334)
Municipal Pumping Sales - Demand Charge	445318	(51,924)	41,782	(45,846)	51,924	(40,935)	45,846	(42,366)	40,935	(39,485)	42,366	(43,972)	39,485	(5,609)
Demand Charge Subtotal														(615,806)
Residential Sales - Customer Charge	440119	(1,117,729)	1,124,185	(1,143,812)	1,117,729	(1,004,374)	1,143,812	(956,500)	1,004,374	(1,052,474)	966,500	(1,029,831)	1,052,474	(32,644)
Commercial Sales - Customer Charge	442219	(681,902)	690,564	(696,200)	681,902	(609,508)	696,200	(587,100)	609,508	(637,575)	587,100	(624,172)	637,575	(6,152)
Industrial Sales - Customer Charge	442319	(33,647)	32,891	(34,126)	33,647	(29,311)	34,126	(27,947)	29,311	(30,595)	27,947	(29,721)	30,595	(155)
Mine Power Sales - Customer Charge	442619	(4,092)	4,098	(4,037)	4,092	(3,763)	4,037	(3,487)	3,763	(3,766)	3,487	(3,789)	3,766	(125)
Street Lighting Sales - Customer Charge	444119	(6,244)	6,289	(6,318)	6,244	(5,601)	6,318	(5,350)	5,601	(5,789)	5,350	(5,645)	5,789	17
Public Authority Sales - Customer Charge	445119	(77,825)	78,611	(79,248)	77,825	(69,780)	79,248	(66,708)	69,780	(72,570)	66,708	(71,267)	72,570	(601)
Municipal Pumping Sales - Customer Charge	445319	(4,198)	4,322	(4,457)	4,198	(3,830)	4,457	(3,694)	3,830	(4,024)	3,694	(3,941)	4,024	(132)
Customer Charge Subtotal														(39,792)
Total Kentucky Utilities Unbilled	173001	$ (48,336,000)	$ 35,825,000	$(55,904,000)	$ 48,336,000	$ (51,947,000)	$ 55,904,000	$ (46,596,000)	$ 51,947,000	$ (46,752,000)	$ 46,596,000	$(39,203,000)	$ 46,752,000	$ (6,878,000)

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		May-07		Jun-07		Jul-07		Aug-07		Sep-07		Oct-07	
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal
Electric Unbilled - Old Dominion Power - Dr (Cr)													
Residential Sales - Energy - Nonfuel	440102	$ (500,686)	$ 528,588	$ (457,927)	$ 500,686	$ (496,371)	$ 457,927	$ (586,525)	$ 496,371	$ (443,134)	$ 586,525	$ (514,099)	$ 443,134
Residential Sales - Energy - Fuel	440103	(395,097)	433,739	(357,349)	395,097	(393,342)	357,349	(471,303)	393,342	(357,133)	471,303	(400,917)	357,133
Residential Sales - MSR	440112	15,783	(17,327)	14,275	(15,783)	15,713	(14,275)	18,828	(15,713)	14,267	(18,828)	16,016	(14,267)
Commercial Sales - Energy - Nonfuel	442202	(202,853)	193,617	(208,013)	202,853	(223,203)	208,013	(222,149)	223,203	(180,095)	222,149	(237,713)	180,095
Commercial Sales - Energy - Fuel	442203	(203,953)	195,393	(210,881)	203,953	(227,815)	210,881	(264,363)	227,815	(185,787)	264,363	(246,905)	185,787
Commercial Sales - MSR	442212	8,148	(7,806)	8,424	(8,148)	9,101	(8,424)	10,561	(9,101)	7,422	(10,561)	9,863	(7,422)
Commercial Sales - Demand Charge	442218	(59,342)	51,796	(58,530)	59,342	(60,082)	58,530	(84,049)	60,082	(48,540)	84,049	(69,245)	48,540
Industrial Sales - Energy - Nonfuel	442302	(47,965)	4,495	(49,717)	47,965	(4,860)	49,717	(5,700)	4,860	(57,989)	5,700	(6,655)	57,989
Industrial Sales - Energy - Fuel	442303	(6,404)	7,636	(10,161)	6,404	(8,898)	10,161	(10,222)	8,898	(6,189)	10,222	(12,162)	6,189
Industrial Sales - MSR	442312	909	(305)	1,066	(909)	355	(1,066)	408	(355)	14,919	(408)	486	(14,919)
Industrial Sales - Demand Charge	442318	(14,540)	3,174	(15,188)	14,540	(3,597)	15,188	(4,486)	3,597	(14,741)	4,486	(5,669)	14,741
Mine Power Sales - Energy - Nonfuel	442602	(115,677)	106,342	(105,519)	115,677	(102,275)	105,519	(103,887)	102,275	(73,592)	103,887	(100,390)	73,592
Mine Power Sales - Energy - Fuel	442603	(242,933)	223,628	(221,719)	242,933	(216,577)	221,719	(217,993)	216,577	(154,042)	217,993	(210,142)	154,042
Mine Power Sales - MSR	442612	9,705	(8,933)	8,857	(9,705)	8,652	(8,857)	8,708	(8,652)	6,154	(8,708)	8,395	(6,154)
Mine Power Sales - Demand Charge	442618	(104,095)	92,964	(104,619)	104,095	(102,800)	104,619	(101,828)	102,800	(74,520)	101,828	(103,863)	74,520
Street Lighting Sales - Energy - NonFuel	444102	(5,054)	4,054	(5,054)	5,054	(4,965)	5,054	(5,788)	4,965	(4,113)	5,788	(5,404)	4,113
Street Lighting Sales - Energy - Fuel	444103	(985)	985	(985)	985	(1,078)	985	(1,262)	1,078	(924)	1,262	(1,663)	924
Street Lighting Sales - MSR	444112	39	(39)	39	(39)	43	(39)	50	(43)	37	(50)	66	(37)
Public Authority Sales - Energy - Nonfuel	445102	(62,136)	57,607	(59,747)	62,136	(56,007)	59,747	(65,171)	56,007	(52,918)	65,171	(70,987)	52,918
Public Authority Sales - Energy - Fuel	445103	(83,564)	77,314	(80,670)	83,564	(74,666)	80,670	(88,090)	74,666	(72,849)	88,090	(95,695)	72,849
Public Authority Sales - MSR	445112	3,338	(3,089)	3,223	(3,338)	2,983	(3,223)	3,519	(2,983)	2,910	(3,519)	3,823	(2,910)
Public Authority Sales - Demand Charge	445118	(23,638)	21,168	(23,806)	23,638	(23,310)	23,806	(25,258)	23,310	(19,143)	25,258	(28,141)	19,143
Municipal Pumping Sales - Energy - Nonfuel	445302	(3,193)	2,778	(3,254)	3,193	(2,706)	3,254	(3,204)	2,706	(2,921)	3,204	(3,157)	2,921
Municipal Pumping Sales - Energy - Fuel	445303	(3,664)	3,233	(3,633)	3,664	(4,218)	3,633	(4,465)	4,218	(3,264)	4,465	(4,619)	3,264
Municipal Pumping Sales - MSR	445312	146	(129)	145	(146)	169	(145)	178	(169)	130	(178)	185	(130)
Municipal Pumping Sales - Demand Charge	445318	(1,290)	1,119	(1,258)	1,290	(1,244)	1,258	(1,510)	1,244	(946)	1,510	(1,409)	946
Total Old Dominion Power Unbilled	173001	$ (2,039,000)	$ 1,972,000	$ (1,942,000)	$ 2,039,000	$ (1,971,000)	$ 1,942,000	$ (2,225,000)	$ 1,971,000	$ (1,707,000)	$ 2,225,000	$ (2,080,000)	$ 1,707,000
Total Company KU Unbilled	173001	$(40,027,000)	$ 34,297,000	$ (41,314,000)	$40,027,000	$(41,974,000)	$ 41,314,000	$ (50,944,000)	$41,974,000	$ (38,631,000)	$ 50,944,000	$ (37,905,000)	$ 38,631,000

Kentucky Utilities Company
Case No. 2008-00251
Electric Unbilled Revenues
For the Test Year Ending April 30, 2008

		Nov-07		Dec-07		Jan-08		Feb-08		Mar-08		Apr-08		Total
	Account #	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	Accrual	Reversal	
Electric Unbilled - Old Dominion Power - Dr (Cr)														
Residential Sales - Energy - Nonfuel	440102	$ (705,002)	$ 514,099	$ (877,525)	$ 705,002	$ (927,759)	$ 877,525	$ (801,092)	$ 927,759	$ (664,514)	$ 801,092	$ (454,130)	$ 664,514	$ 74,459
Residential Sales - Energy - Fuel	440103	(573,926)	400,917	(746,288)	573,926	(807,499)	746,288	(689,450)	807,499	(443,120)	689,450	(301,841)	443,120	131,898
Residential Sales - MSR	440112	22,927	(16,016)	29,813	(22,927)	32,258	(29,813)	27,542	(32,258)	22,634	(27,542)	14,970	(22,634)	(2,357)
Commercial Sales - Energy - Nonfuel	442202	(268,386)	237,713	(270,235)	268,386	(304,304)	270,235	(254,978)	304,304	(228,656)	254,978	(199,072)	228,656	(5,455)
Commercial Sales - Energy - Fuel	442203	(272,338)	246,905	(270,090)	272,338	(300,387)	270,090	(243,857)	300,387	(174,243)	243,857	(160,506)	174,243	34,888
Commercial Sales - MSR	442212	10,879	(9,863)	10,790	(10,879)	12,000	(10,790)	9,742	(12,000)	8,900	(9,742)	7,961	(8,900)	155
Commercial Sales - Demand Charge	442218	(75,156)	69,245	(68,465)	75,156	(72,309)	68,465	(65,907)	72,309	(59,002)	65,907	(55,383)	59,002	(3,588)
Industrial Sales - Energy - Nonfuel	442302	(9,434)	6,655	(8,542)	9,434	(22,630)	8,542	(15,803)	22,630	(17,115)	15,803	(17,348)	17,115	(12,853)
Industrial Sales - Energy - Fuel	442303	(16,565)	12,162	(10,376)	16,565	(34,177)	10,376	(29,158)	34,177	(21,239)	29,158	(21,551)	21,239	(13,915)
Industrial Sales - MSR	442312	662	(486)	415	(662)	1,365	(415)	1,165	(1,365)	1,085	(1,165)	1,069	(1,085)	764
Industrial Sales - Demand Charge	442318	(5,663)	5,669	(5,496)	5,663	(15,559)	5,496	(11,204)	15,559	(13,731)	11,204	(12,169)	13,731	(8,995)
Mine Power Sales - Energy - Nonfuel	442602	(141,744)	100,390	(130,324)	141,744	(154,409)	130,324	(143,747)	154,409	(134,028)	143,747	(116,534)	134,028	(10,192)
Mine Power Sales - Energy - Fuel	442603	(305,375)	210,142	(281,328)	305,375	(328,129)	281,328	(306,207)	328,129	(223,125)	306,207	(201,475)	223,125	22,153
Mine Power Sales - MSR	442612	12,199	(8,395)	11,239	(12,199)	13,108	(11,239)	12,232	(13,108)	11,397	(12,232)	9,993	(11,397)	1,059
Mine Power Sales - Demand Charge	442618	(135,080)	103,863	(111,586)	135,080	(151,571)	111,586	(121,278)	151,571	(115,244)	121,278	(102,983)	115,244	(10,019)
Street Lighting Sales - Energy - NonFuel	444102	(6,197)	5,404	(5,286)	6,197	(7,576)	5,286	(8,813)	7,576	(8,423)	8,813	(8,727)	8,423	(4,673)
Street Lighting Sales - Energy - Fuel	444103	(1,878)	1,663	(1,786)	1,878	(2,525)	1,786	(2,278)	2,525	(1,662)	2,278	(1,339)	1,662	(354)
Street Lighting Sales - MSR	444112	75	(66)	71	(75)	101	(71)	91	(101)	85	(91)	66	(85)	27
Public Authority Sales - Energy - Nonfuel	445102	(81,708)	70,987	(87,715)	81,708	(94,836)	87,715	(81,440)	94,836	(74,455)	81,440	(64,188)	74,455	(6,581)
Public Authority Sales - Energy - Fuel	445103	(107,611)	95,695	(108,750)	107,611	(128,240)	108,750	(104,317)	128,240	(75,370)	104,317	(65,274)	75,370	12,040
Public Authority Sales - MSR	445112	4,299	(3,823)	4,344	(4,299)	5,123	(4,344)	4,167	(5,123)	3,850	(4,167)	3,237	(3,850)	149
Public Authority Sales - Demand Charge	445118	(30,980)	28,141	(24,880)	30,980	(29,047)	24,880	(24,411)	29,047	(24,024)	24,411	(22,776)	24,024	(1,608)
Municipal Pumping Sales - Energy - Nonfuel	445302	(4,255)	3,157	(4,515)	4,255	(2,720)	4,515	(2,332)	2,720	(2,126)	2,332	(2,033)	2,126	745
Municipal Pumping Sales - Energy - Fuel	445303	(5,234)	4,619	(5,265)	5,234	(3,510)	5,265	(2,894)	3,510	(2,095)	2,894	(2,182)	2,095	1,051
Municipal Pumping Sales - MSR	445312	209	(185)	210	(209)	140	(210)	116	(140)	107	(116)	108	(107)	(21)
Municipal Pumping Sales - Demand Charge	445318	(1,720)	1,409	(1,430)	1,720	(910)	1,430	(889)	910	(886)	889	(893)	886	225
Total Old Dominion Power Unbilled	173001	$ (2,697,000)	$ 2,080,000	$ (2,963,000)	$ 2,697,000	$ (3,324,000)	$ 2,963,000	$ (2,855,000)	$ 3,324,000	$ (2,235,000)	$ 2,855,000	$ (1,773,000)	$ 2,235,000	$ 199,000
Total Company KU Unbilled	173001	$ (51,033,000)	$ 37,905,000	$(58,867,000)	$ 51,033,000	$ (55,271,000)	$ 58,867,000	$ (49,451,000)	$ 55,271,000	$ (48,987,000)	$ 49,451,000	$(40,976,000)	$ 48,987,000	$ (6,679,000)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 57

Responding Witness: Shannon L. Charnas

Q-57. Reconcile and explain the difference in unbilled revenues reported at April 30, 2007 of $32,325,000 and those reported at April 30, 2008 of $39,203,000.

A-57. See attached. The increase of $6,878,000 is primarily the result of a higher fuel costs as well as an increase in Environmental Cost Recovery rolled into the energy charge for 2008 as compared to 2007.

Kentucky Utilities Company
Case No. 2008-00251
Unbilled Revenue Reconciliations
For the Periods April 30, 2007 and April 30, 2008

	April 30, 2007	April 30, 2008	Difference
Electric Unbilled - Kentucky Utilities			
Residential Sales - Revenue DSM	$ 118,834	$ 125,133	$ (6,299)
Residential Sales - Energy - Nonfuel	6,061,180	5,912,598	148,582
Residential Sales - Energy - Fuel	3,541,175	4,717,693	(1,176,518)
Residential Sales - FAC		116,449	(116,449)
Residential Sales - ECR	370,483	433,749	(63,266)
Residential Sales - MSR	(163,384)	(191,672)	28,288
Residential Sales - VDT	(36,474)	(34,781)	(1,693)
Residential Sales - Customer Charge	997,187	1,029,831	(32,644)
Commercial Sales - DSM	11,863	12,661	(798)
Commercial Sales - Energy - Nonfuel	2,960,958	3,279,134	(318,176)
Commercial Sales - Energy - Fuel	2,877,900	4,333,992	(1,456,092)
Commercial Sales - FAC		104,871	(104,871)
Commercial Sales - STOD	7,757	5,819	1,938
Commercial Sales - ECR	293,223	384,641	(91,418)
Commercial Sales - MSR	(129,312)	(169,971)	40,659
Commercial Sales - VDT	(28,868)	(30,843)	1,975
Commercial Sales - Demand Charge	1,980,460	2,194,524	(214,064)
Commercial Sales - Customer Charge	618,020	624,173	(6,153)
Industrial Sales - DSM	235	144	91
Industrial Sales - Energy - Nonfuel	1,795,266	1,764,517	30,749
Industrial Sales - Energy - Fuel	4,402,155	6,110,148	(1,707,993)
Industrial Sales - FAC		147,974	(147,974)
Industrial Sales - STOD PCR	6,736	4,556	2,180
Industrial Sales - ECR	333,921	407,516	(73,595)
Industrial Sales - MSR	(147,260)	(180,079)	32,820
Industrial Sales - VDT	(32,875)	(32,678)	(197)
Industrial Sales - Demand Charge	3,005,256	3,124,181	(118,925)
Industrial Sales - Customer Charge	29,566	29,721	(155)
Mine Power Sales - DSM	171	102	69
Mine Power Sales - Energy - Nonfuel	259,786	276,496	(16,710)
Mine Power Sales - Energy - Fuel	465,007	692,497	(227,489)
Mine Power Sales - FAC		15,890	(15,890)
Mine Power Sales - STOD PCR	110	33	77
Mine Power Sales - ECR	39,952	52,021	(12,069)
Mine Power Sales - MSR	(17,619)	(22,988)	5,369
Mine Power Sales - VDT	(3,933)	(4,171)	238

Kentucky Utilities Company
Case No. 2008-00251
Unbilled Revenue Reconciliations
For the Periods April 30, 2007 and April 30, 2008

Mine Power Sales - Demand Charge	398,861	437,331	(38,470)
Mine Power Sales - Customer Charge	3,665	3,789	(125)
Street Lighting Sales- DSM	19	29	(10)
Street Lighting Sales - Energy - Nonfuel	195,619	283,132	(87,513)
Street Lighting Sales - Energy - Fuel	24,924	49,229	(24,305)
Street Lighting Sales - FAC		1,198	(1,198)
Street Lighting Sales - STOD PCR	13	14	(1)
Street Lighting Sales - ECR	7,394	12,537	(5,143)
Street Lighting Sales - MSR	(3,261)	(5,540)	2,279
Street Lighting Sales - VDT	(728)	(1,005)	277
Street Lighting Sales - Demand Charge	3,357	4,761	(1,404)
Street Lighting Sales - Customer Charge	5,663	5,645	17
Public Authority Sales - DSM	1,982	2,987	(1,005)
Public Authority Sales - Energy - Nonfuel	498,745	620,942	(122,196)
Public Authority Sales - Energy - Fuel	740,037	1,406,447	(666,410)
Public Authority Sales - FAC		20,968	(20,968)
Public Authority Sales - STOD PCR	1,731	1,655	76
Public Authority Sales - ECR	67,067	107,653	(40,586)
Public Authority Sales - MSR	(29,577)	(47,571)	17,995
Public Authority Sales - VDT	(6,603)	(8,632)	2,030
Public Authority Sales - Demand Charge	592,952	830,286	(237,334)
Public Authority Sales - Customer Charge	70,666	71,267	(601)
Municipal Pumping Sales - DSM	209	254	(45)
Municipal Pumping Sales - Energy - Nonfuel	41,583	42,506	(922)
Municipal Pumping Sales - Energy - Fuel	48,725	76,383	(27,657)
Municipal Pumping Sales - FAC		1,858	(1,858)
Municipal Pumping Sales - STOD PCR	164	136	28
Municipal Pumping Sales - ECR	4,659	6,174	(1,515)
Municipal Pumping Sales - MSR	(2,055)	(2,728)	674
Municipal Pumping Sales - VDT	(459)	(495)	36
Municipal Pumping Sales - Demand Charge	38,363	43,972	(5,609)
Municipal Pumping Sales - Customer Charge	3,810	3,940	(131)
Total KU Unbilled	$ 32,325,000	$ 39,203,000	$ (6,878,000)

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 58

Responding Witness: Shannon L. Charnas

Q-58. At account 173 - Accrued Utility Revenues, the Uniform System of Accounts states that "In case accruals are made for unbilled revenues, they shall be made likewise for unbilled expenses, such as for purchased power."

a. State the amount of all "unbilled expenses," by account, that was accrued in concurrence with the recording of unbilled revenues as required by the USoA.

b. State why the "unbilled expenses" were not removed from test year operations following the removal of the unbilled revenues.

A-58. a. The Company did not accrue any "unbilled expenses" in concurrence with recording unbilled revenues. However, the Company follows accrual-basis accounting and accordingly records liabilities for all goods and services received in each accounting period. Using this accrual-basis method, each 12-month period contains 12 months worth of expenses.

b. See response to Question No. 54 for an explanation of why unbilled revenues are removed. The Company has historically removed the unbilled revenues in the calculation of rates as approved in KU's last base rate case, Case No. 2003-00434, and LG&E's last base rate case, Case No. 2003-00433, as well as LG&E's Case No. 2000-080 and Case No. 90-158. Accrued expenses were not removed in any of these cases. In its Order in Case No. 2003-00433, the Commission recognized that "the revenues eliminated by LG&E's adjustment included the recovery of environmental surcharge, fuel clause and demand-side management costs that are removed from test-year operating results through various other adjustments". In that case, as in this one, the Company has proposed adjustments for those and other factors that impact the calculation of unbilled revenues, such as changes in the number of customers, to properly normalize for those factors. In its Order, the Commission indicated that any mismatch "is adequately mitigated by the various normalization adjustments included in its rate application". Since the Company made similar adjustments in this case and such adjustments were agreed to by the Commission in the last case, the Company did not propose to remove "unbilled expenses" from test year operations following the removal of the unbilled revenues.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 59

Responding Witness: William Steven Seelye

Q-59. a. Provide a list of all instances by utility name, case number and jurisdiction where Mr. Seelye has proposed and a commission has accepted the exact method of analysis used in this case to develop a temperature normalization adjustment for an electric utility.

b. From the list provided in response to a., provide copies of two recent commission final orders approving the temperature normalization method used by Mr. Seelye.

A-59. Mr. Seelye has not proposed this exact methodology in any other jurisdiction. This methodology was largely developed to address specific concerns expressed by the Commission about earlier proposed temperature normalization adjustments and to include concepts that the Commission indicated that it would expect to be included in an electric temperature normalization adjustment.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 60

Responding Witness: William Steven Seelye

Q-60. a. Provide a list of all instances by utility name, case number, and jurisdiction where Mr. Seelye has proposed and a commission has rejected the exact method of analysis used in this case to develop a temperature normalization adjustment for an electric utility.

b. From the list provided in response to a., provide copies of two recent commission final orders denying the temperature normalization method used by Mr. Seelye.

A-60. Mr. Seelye has not proposed this exact methodology in any other jurisdiction. This methodology was largely developed to address specific concerns expressed by the Commission about earlier proposed temperature normalization adjustments and to include concepts that the Commission indicated that it would expect to be included in an electric temperature normalization adjustment.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 61

Responding Witness: William Steven Seelye

Q-61. Compare and contrast, in full detail, the method used by Mr. Seelye to develop his weather normalization adjustment as discussed in his testimony at pages 19–51 to the methods used by KU to weather normalize revenues and expenses when developing annual budgets and forecasts.

A-61. The KU load forecasting methodology is based on econometric modeling of energy sales by customer class, but also incorporates specific intelligence on the prospective energy requirements of the utility's largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as weather (expressed in monthly heating and cooling degree days), the number of households, or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

KU utilizes a forecast of 'normal' monthly weather – computed as the average of monthly heating and cooling degree-days over the past 20-years – to produce its weather-normalized electric sales forecast. In its standard variance reporting process, the impact of non-normal weather is measured by multiplying class-specific weather coefficients derived in its econometric modeling process by the deviation in actual weather from normal. In more rigorous analyses of the impact of non-normal weather on electricity sales, KU utilizes the weather-normalization process applied by Mr. Seelye in this proceeding.

The following are key differences between the weather-normalization process employed by KU in its standard variance reporting process ("KU Process") and the process applied by Mr. Seelye ("Seelye Process"):

1. In each process, a weather-adjustment is computed by multiplying weather coefficients by a deviation in actual weather from 'normal.' The weather deviation utilized in the KU Process is larger than the deviation utilized in the Seelye Process. In the KU Process, the weather deviation is computed as the difference between actual weather (measured in degree-days) and the 20-year average of degree days. In

the Seelye Process, the weather deviation is computed as the difference between actual weather and the outer bound of a 'range' of normal weather.

2. The KU Process utilizes multiple years of monthly historical usage data in the derivation of its weather coefficients. In addition to weather variables, the KU Process utilizes various economic and demographic variables as independent variables in its econometric modeling process. The Seelye Process utilizes daily usage data for the month that is being weather-normalized in the derivation of its weather coefficients. Because the Seelye process focuses directly on the month in question, the impact of economic and demographic factors can be assumed constant throughout the month. As a result, the somewhat subjective process of selecting economic and demographic independent variables can be avoided with the Seelye Process.

3. By utilizing daily usage data, the Seelye Process is able to match the daily usage data precisely to the daily weather data. In the KU Process, the average usage across 20 billing cycles for a given billing month is matched to the average number of degree days for the month.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 62

Responding Witness: William Steven Seelye

Q-62. Refer to pages 20-51 of the Seelye Testimony and Seelye Exhibits 8-13 concerning the proposed electric temperature normalization adjustment.

a. Pages 35-39 include a discussion of the step-wise regression procedure performed using the "Stepwise" model selection method in the SAS statistical software package and a description of the variables, or regressors, that were considered in the step-wise regression process. Explain whether the headings of Columns 1-6 in Seelye Exhibit 12 reflect the variables that were not deleted by the model under the step-wise regression process.

b. Are the amounts in the "Total Adjustment" column for the first 26 lines on Exhibit 12, page 1 of 5, intended to sum the amount of 119,925,000 kWh shown on the first and second lines of Column 1 of Exhibit 19?

c. The first and second numbered columns in Exhibit 12 appear to have the headings HDD60 and HDD 65, which represent heating degree days using a 60 and 65 degree base, respectively. Explain why Exhibit 12 appears to show heating degree days outside of the range for month 4 while Exhibit 9 appears to show days outside the range for months 9 and 10.

d. Is it correct that the results from the "Stepwise" model selection method, as shown on Exhibit 12, page 1 of 5, produce kWh adjustments for the residential class in the following months based on these different variables/regressors:

(1) Month 5, CDD70 and Maximum Temperature

(2) Month 8, CDD70

(3) Month 9, CDD65

(4) Month 10, CDD 65

(5) Month 5, CDD70 and Maximum Temperature

(6) Month 8, CDD8

(7) Month 9, CDD9

(8) Month 10, CDD 70 and Minimum Temperature

e. The testimony states that step-wise regression removes the risk of judgment and bias on the part of the analyst in determining which subset of regressors should be included in a model. Explain whether the removal of such risk outweighs the expectation of a greater degree of consistency in quantifying the relationship between temperature and electricity consumption.

f. Provide two revised runs of Seelye Exhibits 12 and 13, one which includes HDD65 and CDD as the only variables and a second which includes HDD60 and CDD as the only variables.

g. Explain how it was determined that the specific expense accounts listed on Exhibit 14, which are all production expense accounts, are the only expense accounts to be included in calculating the expense portion of the adjustment.

h. Provide workpapers, and evidence supporting the workpapers, calculating the actual and 30-year average cooling and heating degree days included in Exhibit 9, page 1 of the Seelye Testimony.

A-62. a. The headings reflect the temperature variables in the model. In many cases, the variables shown in the heading were removed in the stepwise process. For example, if the value for a variable is zero in a month, then the variable was not included in the final model through the application of the stepwise procedure. In addition, the table does not indicate the non-temperature dichotomous variables that were included in the model, such as Weekend, Monday, and Friday. Including these dichotomous variables will often significantly improve how well the model fits the data. The variables that were ultimately selected are shown in Seelye Exhibit 12 for each month and for each rate class for which a temperature normalization adjustment was made.

b. No. These figures should sum to the 158,831,000 amount shown on Seelye *Exhibit 13*.

c. The table in Exhibit 12 shows information for HDD65 and CDD65, but does not show information for any of the other HDD variables, including HDD60. As can be seen on page 1 of Seelye Exhibit 12, there is an adjustment for HDD60 in month 4 but not an adjustment for HDD65. As can be seen on page 4 of Seelye Exhibit 18, the actual HDD60 is outside of the range for HDD60, even though HDD65 is inside the range for HDD65.

d. Yes, for items (1) through (5). No, for items (6) through (8). There appears to be typographical problems in items (5) through (8).

e. The Company gave a great deal of consideration to the issue posed in the question. Including a wider range of potential temperature variables in the model and allowing those variables to change from month to month will certainly improve the fit of the model for any given month. But, as the question suggests, allowing for different temperature variables to be used will reduce the consistency in quantifying the relationship between temperature and electric consumption from month to month. Consequently, there is a tradeoff between the accuracy of the model on one hand and consistency of results on the other hand. Ultimately, the principal consideration that motivated the Company to select the stepwise approach was that it wanted to adequately address the criticisms made by the Commission of LG&E's previous temperature normalization methodologies. For example, in its Order in Case No. 10064, the Commission indicated that LG&E should consider a range of weather variables. This encouraged the Company to develop a stepwise procedure using a range of weather variables.

f. The Company is compiling the revised results and will provide the requested information in a supplemental response to this question.

g. The accounts listed on Seelye Exhibit 20, which were used to calculate the expense component of the temperature adjustment, are the accounts identified in the Company's cost of service study that are classified as variable expenses. In the cost of service study, all of the Company's costs are classified as either fixed (demand or customer) or variable (energy). Consistent with prior cost of service studies, only production operation and maintenance expenses are classified as variable (i.e., they vary with the amount of kWh produced by the generators). The Company's transmission and distribution expenses do not vary with the amount of kWh delivered to customers. See response to Question No. 42.

h. See attached.

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1978	1	3	31	0	0	1,305	1,150
SDF	1979	1	3	31	0	0	1,254	1,099
SDF	1980	1	3	31	0	0	978	823
SDF	1981	1	3	31	0	0	1,074	919
SDF	1982	1	3	31	0	0	1,129	974
SDF	1983	1	3	31	0	0	940	785
SDF	1984	1	3	31	0	0	1,122	967
SDF	1985	1	3	31	0	0	1,227	1,072
SDF	1986	1	3	31	0	0	948	793
SDF	1987	1	3	31	0	0	971	816
SDF	1988	1	3	31	0	0	1,056	901
SDF	1989	1	3	31	0	0	726	571
SDF	1990	1	3	31	0	0	679	524
SDF	1991	1	3	31	0	0	957	802
SDF	1992	1	3	31	0	0	863	708
SDF	1993	1	3	31	0	0	824	669
SDF	1994	1	3	31	0	0	1,186	1,031
SDF	1995	1	3	31	0	0	911	763
SDF	1996	1	3	31	0	0	1,010	855
SDF	1997	1	3	31	0	0	1,018	869
SDF	1998	1	3	31	0	0	710	557
SDF	1999	1	3	31	0	0	882	728
SDF	2000	1	3	31	0	0	956	803
SDF	2001	1	3	31	0	0	999	844
SDF	2002	1	3	31	0	0	754	604
SDF	2003	1	3	31	0	0	1,124	969
SDF	2004	1	3	31	0	0	993	843
SDF	2005	1	3	31	1	0	824	674
SDF	2006	1	3	31	0	0	651	496
SDF	2007	1	3	31	0	0	812	659
SDF	1978	2	3	28	0	0	1,153	1,013
SDF	1979	2	3	28	0	0	1,038	898
SDF	1980	2	3	29	0	0	1,029	884
SDF	1981	2	3	28	0	0	735	595
SDF	1982	2	3	28	0	0	845	705
SDF	1983	2	3	28	0	0	771	631
SDF	1984	2	3	29	0	0	683	538
SDF	1985	2	3	28	2	0	904	769
SDF	1986	2	3	28	0	0	702	564
SDF	1987	2	3	28	0	0	715	575
SDF	1988	2	3	29	0	0	879	734
SDF	1989	2	3	28	0	0	867	727
SDF	1990	2	3	28	0	0	581	442
SDF	1991	2	3	28	0	0	686	546
SDF	1992	2	3	29	0	0	614	469
SDF	1993	2	3	28	0	0	868	728
SDF	1994	2	3	28	0	0	757	619
SDF	1995	2	3	28	0	0	806	666
SDF	1996	2	3	29	0	0	790	652

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1997	2	3	28	0	0	646	508
SDF	1998	2	3	28	0	0	604	464
SDF	1999	2	3	28	0	0	647	507
SDF	2000	2	3	29	5	0	587	453
SDF	2001	2	3	28	0	0	677	537
SDF	2002	2	3	28	0	0	688	548
SDF	2003	2	3	28	0	0	909	769
SDF	2004	2	3	29	0	0	767	622
SDF	2005	2	3	28	0	0	658	518
SDF	2006	2	3	28	0	0	763	624
SDF	2007	2	3	28	0	0	980	840
SDF	1978	3	3	31	0	0	725	574
SDF	1979	3	3	31	5	0	524	393
SDF	1980	3	3	31	0	0	721	566
SDF	1981	3	3	31	5	0	605	462
SDF	1982	3	3	31	1	0	555	414
SDF	1983	3	3	31	6	0	575	439
SDF	1984	3	3	31	0	0	764	609
SDF	1985	3	3	31	8	1	467	324
SDF	1986	3	3	31	5	0	524	389
SDF	1987	3	3	31	0	0	531	377
SDF	1988	3	3	31	4	0	589	449
SDF	1989	3	3	31	6	1	521	382
SDF	1990	3	3	31	21	1	451	325
SDF	1991	3	3	31	7	0	491	358
SDF	1992	3	3	31	2	0	532	400
SDF	1993	3	3	31	0	0	653	503
SDF	1994	3	3	31	0	0	609	455
SDF	1995	3	3	31	0	0	479	334
SDF	1996	3	3	31	0	0	745	593
SDF	1997	3	3	31	0	0	485	335
SDF	1998	3	3	31	42	16	574	451
SDF	1999	3	3	31	0	0	686	533
SDF	2000	3	3	31	3	0	430	290
SDF	2001	3	3	31	0	0	685	530
SDF	2002	3	3	31	0	0	590	440
SDF	2003	3	3	31	0	0	484	344
SDF	2004	3	3	31	18	2	451	322
SDF	2005	3	3	31	0	0	670	517
SDF	2006	3	3	31	0	0	559	410
SDF	2007	3	3	31	48	6	350	260
SDF	1978	4	3	30	19	1	228	118
SDF	1979	4	3	30	9	0	309	191
SDF	1980	4	3	30	7	1	349	219
SDF	1981	4	3	30	66	20	145	76
SDF	1982	4	3	30	2	0	414	274
SDF	1983	4	3	30	7	0	408	280
SDF	1984	4	3	30	20	4	322	202
SDF	1985	4	3	30	46	6	187	116

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1986	4	3	30	35	4	230	142
SDF	1987	4	3	30	13	1	302	187
SDF	1988	4	3	30	9	0	250	128
SDF	1989	4	3	30	47	22	296	194
SDF	1990	4	3	30	42	14	327	228
SDF	1991	4	3	30	29	0	170	93
SDF	1992	4	3	30	42	7	252	166
SDF	1993	4	3	30	4	0	308	191
SDF	1994	4	3	30	42	16	194	102
SDF	1995	4	3	30	27	5	243	136
SDF	1996	4	3	30	18	1	360	248
SDF	1997	4	3	30	1	0	375	241
SDF	1998	4	3	30	2	0	273	152
SDF	1999	4	3	30	12	2	198	105
SDF	2000	4	3	30	0	0	291	164
SDF	2001	4	3	30	97	47	183	107
SDF	2002	4	3	30	73	30	210	130
SDF	2003	4	3	30	41	6	219	131
SDF	2004	4	3	30	36	5	216	129
SDF	2005	4	3	30	26	3	215	125
SDF	2006	4	3	30	50	19	158	70
SDF	2007	4	3	30	49	11	333	240
SDF	1978	5	3	31	107	47	146	78
SDF	1979	5	3	31	70	23	96	36
SDF	1980	5	3	31	127	42	71	25
SDF	1981	5	3	31	60	13	126	46
SDF	1982	5	3	31	177	64	14	0
SDF	1983	5	3	31	36	1	127	45
SDF	1984	5	3	31	67	16	143	61
SDF	1985	5	3	31	102	32	54	17
SDF	1986	5	3	31	134	40	72	34
SDF	1987	5	3	31	225	115	25	3
SDF	1988	5	3	31	106	37	41	7
SDF	1989	5	3	31	85	37	161	79
SDF	1990	5	3	31	60	7	85	25
SDF	1991	5	3	31	280	159	29	7
SDF	1992	5	3	31	95	26	129	62
SDF	1993	5	3	31	102	29	46	7
SDF	1994	5	3	31	61	21	125	43
SDF	1995	5	3	31	96	31	76	28
SDF	1996	5	3	31	177	83	69	30
SDF	1997	5	3	31	33	12	151	58
SDF	1998	5	3	31	193	91	29	5
SDF	1999	5	3	31	95	21	19	1
SDF	2000	5	3	31	149	61	29	7
SDF	2001	5	3	31	142	54	35	4
SDF	2002	5	3	31	107	44	118	53
SDF	2003	5	3	31	81	22	56	11
SDF	2004	5	3	31	244	120	41	23

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	2005	5	3	31	81	15	99	51
SDF	2006	5	3	31	103	59	103	29
SDF	2007	5	3	31	197	93	28	5
SDF	1978	6	3	30	320	186	1	0
SDF	1979	6	3	30	271	139	5	0
SDF	1980	6	3	30	259	140	8	0
SDF	1981	6	3	30	334	189	0	0
SDF	1982	6	3	30	133	44	4	0
SDF	1983	6	3	30	258	135	6	0
SDF	1984	6	3	30	380	235	1	0
SDF	1985	6	3	30	228	101	17	4
SDF	1986	6	3	30	322	180	0	0
SDF	1987	6	3	30	337	192	0	0
SDF	1988	6	3	30	327	206	8	0
SDF	1989	6	3	30	258	136	4	0
SDF	1990	6	3	30	317	177	14	4
SDF	1991	6	3	30	398	251	0	0
SDF	1992	6	3	30	217	96	10	0
SDF	1993	6	3	30	303	177	19	1
SDF	1994	6	3	30	376	234	4	0
SDF	1995	6	3	30	297	159	0	0
SDF	1996	6	3	30	289	164	2	0
SDF	1997	6	3	30	221	113	15	0
SDF	1998	6	3	30	315	190	18	2
SDF	1999	6	3	30	335	196	0	0
SDF	2000	6	3	30	299	167	3	0
SDF	2001	6	3	30	273	146	11	0
SDF	2002	6	3	30	383	243	0	0
SDF	2003	6	3	30	197	81	16	0
SDF	2004	6	3	30	329	181	0	0
SDF	2005	6	3	30	358	215	1	0
SDF	2006	6	3	30	260	121	0	0
SDF	2007	6	3	30	374	224	0	0
SDF	1978	7	3	31	419	264	0	0
SDF	1979	7	3	31	317	167	0	0
SDF	1980	7	3	31	511	356	0	0
SDF	1981	7	3	31	426	276	0	0
SDF	1982	7	3	31	402	250	0	0
SDF	1983	7	3	31	498	351	0	0
SDF	1984	7	3	31	325	173	0	0
SDF	1985	7	3	31	378	223	0	0
SDF	1986	7	3	31	474	319	0	0
SDF	1987	7	3	31	432	277	0	0
SDF	1988	7	3	31	474	320	0	0
SDF	1989	7	3	31	405	252	0	0
SDF	1990	7	3	31	420	268	0	0
SDF	1991	7	3	31	504	349	0	0
SDF	1992	7	3	31	409	254	0	0
SDF	1993	7	3	31	525	370	0	0

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1994	7	3	31	434	279	0	0
SDF	1995	7	3	31	457	303	0	0
SDF	1996	7	3	31	331	176	0	0
SDF	1997	7	3	31	424	273	0	0
SDF	1998	7	3	31	410	255	0	0
SDF	1999	7	3	31	564	409	0	0
SDF	2000	7	3	31	366	211	0	0
SDF	2001	7	3	31	422	268	0	0
SDF	2002	7	3	31	508	353	0	0
SDF	2003	7	3	31	383	228	0	0
SDF	2004	7	3	31	387	235	0	0
SDF	2005	7	3	31	450	295	0	0
SDF	2006	7	3	31	444	290	0	0
SDF	2007	7	3	31	391	236	0	0
SDF	1978	8	3	31	374	219	0	0
SDF	1979	8	3	31	343	203	1	0
SDF	1980	8	3	31	494	339	0	0
SDF	1981	8	3	31	342	187	0	0
SDF	1982	8	3	31	264	128	1	0
SDF	1983	8	3	31	515	360	0	0
SDF	1984	8	3	31	341	190	0	0
SDF	1985	8	3	31	304	154	0	0
SDF	1986	8	3	31	299	160	12	1
SDF	1987	8	3	31	409	256	0	0
SDF	1988	8	3	31	465	318	0	0
SDF	1989	8	3	31	358	216	0	0
SDF	1990	8	3	31	386	235	0	0
SDF	1991	8	3	31	439	284	0	0
SDF	1992	8	3	31	254	118	0	0
SDF	1993	8	3	31	434	279	0	0
SDF	1994	8	3	31	342	193	0	0
SDF	1995	8	3	31	536	381	0	0
SDF	1996	8	3	31	375	220	0	0
SDF	1997	8	3	31	317	176	0	0
SDF	1998	8	3	31	426	271	0	0
SDF	1999	8	3	31	412	257	0	0
SDF	2000	8	3	31	374	219	0	0
SDF	2001	8	3	31	437	282	0	0
SDF	2002	8	3	31	487	332	0	0
SDF	2003	8	3	31	400	245	0	0
SDF	2004	8	3	31	285	154	2	0
SDF	2005	8	3	31	488	333	0	0
SDF	2006	8	3	31	444	289	0	0
SDF	2007	8	3	31	622	467	0	0
SDF	1978	9	3	30	264	145	5	0
SDF	1979	9	3	30	151	62	20	1
SDF	1980	9	3	30	268	153	14	2
SDF	1981	9	3	30	144	57	62	18
SDF	1982	9	3	30	114	43	60	15

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1983	9	3	30	235	133	56	31
SDF	1984	9	3	30	141	55	75	34
SDF	1985	9	3	30	182	99	57	12
SDF	1986	9	3	30	250	128	7	0
SDF	1987	9	3	30	196	96	10	0
SDF	1988	9	3	30	167	59	14	1
SDF	1989	9	3	30	181	87	52	20
SDF	1990	9	3	30	238	133	36	13
SDF	1991	9	3	30	257	161	55	17
SDF	1992	9	3	30	158	73	52	22
SDF	1993	9	3	30	140	53	50	25
SDF	1994	9	3	30	131	51	22	2
SDF	1995	9	3	30	160	69	49	24
SDF	1996	9	3	30	148	79	37	2
SDF	1997	9	3	30	164	66	9	0
SDF	1998	9	3	30	327	194	1	0
SDF	1999	9	3	30	232	130	23	3
SDF	2000	9	3	30	153	71	64	20
SDF	2001	9	3	30	166	73	56	21
SDF	2002	9	3	30	306	179	2	0
SDF	2003	9	3	30	124	44	41	16
SDF	2004	9	3	30	213	87	8	0
SDF	2005	9	3	30	283	145	10	0
SDF	2006	9	3	30	94	20	46	15
SDF	2007	9	3	30	344	206	3	0
SDF	1978	10	3	31	6	1	301	166
SDF	1979	10	3	31	36	11	248	141
SDF	1980	10	3	31	30	4	315	205
SDF	1981	10	3	31	9	3	275	152
SDF	1982	10	3	31	66	18	252	154
SDF	1983	10	3	31	18	4	201	89
SDF	1984	10	3	31	53	2	88	42
SDF	1985	10	3	31	54	15	167	77
SDF	1986	10	3	31	45	25	217	99
SDF	1987	10	3	31	1	0	386	236
SDF	1988	10	3	31	10	1	406	268
SDF	1989	10	3	31	29	3	236	132
SDF	1990	10	3	31	40	6	236	130
SDF	1991	10	3	31	64	19	174	94
SDF	1992	10	3	31	18	3	222	102
SDF	1993	10	3	31	11	0	295	178
SDF	1994	10	3	31	20	1	194	88
SDF	1995	10	3	31	19	0	197	98
SDF	1996	10	3	31	16	0	214	110
SDF	1997	10	3	31	76	29	269	170
SDF	1998	10	3	31	43	17	133	55
SDF	1999	10	3	31	11	0	202	107
SDF	2000	10	3	31	66	19	181	99
SDF	2001	10	3	31	37	2	231	137

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	2002	10	3	31	49	25	262	144
SDF	2003	10	3	31	15	3	224	117
SDF	2004	10	3	31	22	4	135	42
SDF	2005	10	3	31	69	25	211	126
SDF	2006	10	3	31	29	10	317	207
SDF	2007	10	3	31	146	75	118	51
SDF	1978	11	3	30	2	0	451	307
SDF	1979	11	3	30	0	0	544	397
SDF	1980	11	3	30	1	0	562	422
SDF	1981	11	3	30	0	0	531	390
SDF	1982	11	3	30	12	3	503	368
SDF	1983	11	3	30	0	0	517	369
SDF	1984	11	3	30	0	0	631	482
SDF	1985	11	3	30	13	3	353	237
SDF	1986	11	3	30	0	0	575	431
SDF	1987	11	3	30	3	0	428	305
SDF	1988	11	3	30	0	0	516	368
SDF	1989	11	3	30	0	0	549	404
SDF	1990	11	3	30	7	2	397	266
SDF	1991	11	3	30	0	0	599	465
SDF	1992	11	3	30	0	0	510	366
SDF	1993	11	3	30	1	0	586	441
SDF	1994	11	3	30	4	0	390	256
SDF	1995	11	3	30	0	0	699	552
SDF	1996	11	3	30	0	0	698	548
SDF	1997	11	3	30	0	0	633	485
SDF	1998	11	3	30	0	0	429	285
SDF	1999	11	3	30	5	0	356	232
SDF	2000	11	3	30	2	0	618	486
SDF	2001	11	3	30	0	0	352	214
SDF	2002	11	3	30	3	0	598	458
SDF	2003	11	3	30	15	0	389	274
SDF	2004	11	3	30	2	0	411	270
SDF	2005	11	3	30	5	0	476	348
SDF	2006	11	3	30	2	0	479	342
SDF	2007	11	3	30	2	0	490	353
SDF	1978	12	3	31	0	0	774	619
SDF	1979	12	3	31	0	0	801	646
SDF	1980	12	3	31	0	0	828	676
SDF	1981	12	3	31	0	0	967	812
SDF	1982	12	3	31	7	0	631	497
SDF	1983	12	3	31	0	0	1,135	980
SDF	1984	12	3	31	1	0	593	458
SDF	1985	12	3	31	0	0	1,075	920
SDF	1986	12	3	31	0	0	877	722
SDF	1987	12	3	31	0	0	770	615
SDF	1988	12	3	31	0	0	840	685
SDF	1989	12	3	31	0	0	1,230	1,075
SDF	1990	12	3	31	0	0	753	598

Monthly Totals

Station	Year	Month	_TYPE_	_FREQ_	cdd65	cdd70	hdd65	hdd60
SDF	1991	12	3	31	0	0	733	580
SDF	1992	12	3	31	0	0	817	662
SDF	1993	12	3	31	0	0	857	702
SDF	1994	12	3	31	0	0	702	547
SDF	1995	12	3	31	0	0	924	771
SDF	1996	12	3	31	0	0	747	599
SDF	1997	12	3	31	0	0	861	706
SDF	1998	12	3	31	5	0	736	598
SDF	1999	12	3	31	0	0	812	657
SDF	2000	12	3	31	0	0	1,218	1,063
SDF	2001	12	3	31	0	0	699	545
SDF	2002	12	3	31	0	0	833	678
SDF	2003	12	3	31	0	0	796	641
SDF	2004	12	3	31	0	0	881	726
SDF	2005	12	3	31	0	0	964	809
SDF	2006	12	3	31	0	0	681	530
SDF	2007	12	3	31	0	0	716	561

Annual Totals

Year	cdd65	cdd70	hdd65	hdd60
1978	1,509	861	5,087	4,024
1979	1,200	603	4,838	3,800
1980	1,696	1,033	4,872	3,819
1981	1,384	743	4,518	3,468
1982	1,176	547	4,406	3,398
1983	1,572	983	4,733	3,647
1984	1,325	674	4,419	3,391
1985	1,316	632	4,506	3,546
1986	1,562	855	4,162	3,173
1987	1,614	936	4,136	3,113
1988	1,560	940	4,597	3,539
1989	1,368	752	4,640	3,583
1990	1,530	841	3,556	2,552
1991	1,976	1,222	3,893	2,961
1992	1,194	575	3,998	2,954
1993	1,518	906	4,504	3,443
1994	1,409	793	4,180	3,141
1995	1,590	946	4,383	3,370
1996	1,352	722	4,671	3,636
1997	1,235	669	4,462	3,371
1998	1,761	1,032	3,503	2,567
1999	1,665	1,015	3,824	2,871
2000	1,415	747	4,374	3,383
2001	1,573	871	3,926	2,937
2002	1,914	1,205	4,054	3,053
2003	1,255	628	4,256	3,270
2004	1,535	785	3,903	2,975
2005	1,760	1,030	4,126	3,168
2006	1,425	807	3,756	2,722
2007	2,170	1,316	3,829	2,967

30-Year Average

Month	cdd65	cdd70	hdd65	hdd60
1	0	0	963	809
2	0	0	778	638
3	6	1	567	426
4	29	7	265	163
5	120	47	78	29
6	299	167	5	0
7	429	276	0	0
8	399	249	1	0
9	198	98	33	10
10	37	11	230	127
11	2	0	509	370
12	0	0	841	689

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 63

Responding Witness: William Steven Seelye

Q-63. Page 45, line 11, of the Seelye Testimony states that a 30-year average value was used in Exhibit 12. Explain why the last two columns on pages 4 and 5 of Exhibit 12 indicate that a 20-year average was used.

A-63. In calculating the adjustment, 30-year average values were used. The appearance of 20-year averages on Seelye Exhibit 12 was the result of a printing problem with the model. See response to Question No. 65.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 64

Responding Witness: William Steven Seelye

Q-64. Provide the calculations of the "kilo Watt-Hour Adjustment to Usage" for each rate class as shown in Exhibit 13 of the Seelye Testimony.

A-64. See attached. The spreadsheet is also being provided on CD in response to Question No. 30.

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
1	2007	4	1	KU	-515.904	0	0	0	0	0	0	0	-515.904	RS
1	2007	5	1	KU	0	0	0	-5509.5	0	-8481.35	0	0	-13990.9	RS
1	2007	6	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	7	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	8	1	KU	0	0	0	-34825.6	0	0	0	0	-34825.6	RS
1	2007	9	1	KU	0	0	-12882.7	0	0	0	0	0	-12882.7	RS
1	2007	10	1	KU	0	0	-15740.6	0	0	0	0	0	-15740.6	RS
1	2007	11	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2007	12	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	1	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	2	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	3	1	KU	0	0	0	0	0	0	0	0	0	RS
1	2008	4	1	KU	0	0	0	0	0	0	0	0	0	RS
2	2007	4	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	5	20	KU	0	0	0	-3168.59	0	-3312.2	0	0	-6480.79	RS (formerly Full Electric)
2	2007	6	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	7	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	8	20	KU	0	0	-20124.5	0	0	0	0	0	-20124.5	RS (formerly Full Electric)
2	2007	9	20	KU	0	0	-8243.08	0	0	0	0	0	-8243.08	RS (formerly Full Electric)
2	2007	10	20	KU	0	0	0	-9874.11	2753.166	0	0	0	-7120.94	RS (formerly Full Electric)
2	2007	11	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2007	12	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	1	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	2	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	3	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
2	2008	4	20	KU	0	0	0	0	0	0	0	0	0	RS (formerly Full Electric)
3	2007	4	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	5	100	KU	0	0	0	0	0	-2580.28	0	0	-2580.28	C/I GS Sec
3	2007	6	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	7	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	8	100	KU	0	0	-5786.62	0	0	0	0	0	-5786.62	C/I GS Sec
3	2007	9	100	KU	0	0	-2606.28	0	0	0	0	0	-2606.28	C/I GS Sec
3	2007	10	100	KU	0	0	-3893.59	0	0	0	0	0	-3893.59	C/I GS Sec
3	2007	11	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2007	12	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	1	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	2	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	3	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
3	2008	4	100	KU	0	0	0	0	0	0	0	0	0	C/I GS Sec
4	2007	4	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	5	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	6	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	7	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	8	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	9	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	10	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	11	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2007	12	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2008	1	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2008	2	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2008	3	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
4	2008	4	120	KU	0	0	0	0	0	0	0	0	0	C/I GS Pri
5	2007	4	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	5	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	6	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	7	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	8	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	9	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	10	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	11	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2007	12	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2008	1	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2008	2	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2008	3	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
5	2008	4	140	KU	0	0	0	0	0	0	0	0	0	C/I GS Schools
6	2007	4	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	5	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	6	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	7	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	8	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	9	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	10	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	11	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2007	12	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2008	1	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2008	2	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2008	3	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
6	2008	4	160	KU	0	0	0	0	0	0	0	0	0	C/I GS Net Meter
7	2007	4	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	5	200	KU	0	0	-49.229	0	0	-86.3412	0	0	-135.57	C/I LP STOD Sec
7	2007	6	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	7	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	8	200	KU	0	0	0	0	-57.2506	-255.49	0	0	-312.74	C/I LP STOD Sec
7	2007	9	200	KU	0	0	0	-69.504	0	-52.998	0	0	-122.502	C/I LP STOD Sec
7	2007	10	200	KU	0	-50.882	-219.261	0	0	0	0	0	-270.143	C/I LP STOD Sec

Note: Formulas change half-way down the page!!!

Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
					1	2	3	4	5	6	7	8		
7	2007	11	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2007	12	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	1	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	2	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	3	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
7	2008	4	200	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Sec
8	2007	4	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	5	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	6	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	7	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	8	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	9	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	10	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	11	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2007	12	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2008	1	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2008	2	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2008	3	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
8	2008	4	210	KU	0	0	0	0	0	0	0	0	0	C/I LP STOD Pri
9	2007	4	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	5	300	KU	0	0	-814 435	0	0	0	0	0	-814 435	C/I LP Sec
9	2007	6	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	7	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	8	300	KU	0	0	-6333 37	0	0	0	0	0	-6333 37	C/I LP Sec
9	2007	9	300	KU	0	0	-2481 22	0	0	0	0	0	-2481.22	C/I LP Sec
9	2007	10	300	KU	0	0	-2047 13	0	-2293.02	0	0	0	-4340 15	C/I LP Sec
9	2007	11	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2007	12	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	1	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	2	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	3	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
9	2008	4	300	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec
10	2007	4	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	5	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	6	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	7	305	KU	0	0	0	0	566.556	0	0	0	566.556	C/I LP Sec PF
10	2007	8	305	KU	0	0	0	-1848 98	0	0	0	0	-1848 98	C/I LP Sec PF
10	2007	9	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	10	305	KU	0	0	-1093 13	0	-887 555	0	0	0	-1980 68	C/I LP Sec PF
10	2007	11	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2007	12	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	1	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	2	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	3	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
10	2008	4	305	KU	0	0	0	0	0	0	0	0	0	C/I LP Sec PF
11	2007	4	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	5	320	KU	0	0	0	-112 5	0	0	0	0	-112 5	C/I LP Pri
11	2007	6	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	7	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	8	320	KU	0	0	-435 896	0	0	0	0	0	-435.896	C/I LP Pri
11	2007	9	320	KU	0	0	-162.689	0	0	0	0	0	-162 689	C/I LP Pri
11	2007	10	320	KU	0	0	-209 35	0	0	0	0	0	-209 35	C/I LP Pri
11	2007	11	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2007	12	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	1	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	2	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	3	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
11	2008	4	320	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri
12	2007	4	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	5	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	6	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	7	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	8	325	KU	0	0	-1648.82	0	0	0	0	0	-1648.82	C/I LP Pri PF
12	2007	9	325	KU	0	0	-971.879	0	0	0	0	0	-971.879	C/I LP Pri PF
12	2007	10	325	KU	0	0	-2425 49	0	0	0	0	0	-2425.49	C/I LP Pri PF
12	2007	11	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2007	12	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	1	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	2	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	3	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
12	2008	4	325	KU	0	0	0	0	0	0	0	0	0	C/I LP Pri PF
13	2007	4	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	5	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	6	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	7	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	8	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	9	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	10	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	11	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2007	12	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2008	1	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2008	2	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2008	3	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
13	2008	4	345	KU	0	0	0	0	0	0	0	0	0	C/I LP Trans PF
14	2007	4	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
14	2007	5	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	6	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	7	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	8	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	9	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	10	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	11	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2007	12	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2008	1	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2008	2	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2008	3	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
14	2008	4	420	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Pri PF
15	2007	4	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	5	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	6	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	7	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	8	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	9	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	10	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	11	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2007	12	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2008	1	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2008	2	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2008	3	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
15	2008	4	440	KU	0	0	0	0	0	0	0	0	0	Lg C/I LCI-TOD Trans PF
16	2007	4	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	5	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	6	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	7	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	8	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	9	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	10	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	11	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2007	12	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2008	1	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2008	2	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2008	3	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
16	2008	4	500	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri
17	2007	4	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	5	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	6	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	7	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	8	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	9	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	10	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	11	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2007	12	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2008	1	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2008	2	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2008	3	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
17	2008	4	505	KU	0	0	0	0	0	0	0	0	0	C/I Mines Pri PF
18	2007	4	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	5	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	6	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	7	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	8	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	9	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	10	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	11	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2007	12	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2008	1	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2008	2	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2008	3	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
18	2008	4	510	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans
19	2007	4	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	5	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	6	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	7	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	8	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	9	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	10	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	11	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2007	12	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2008	1	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2008	2	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2008	3	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
19	2008	4	515	KU	0	0	0	0	0	0	0	0	0	C/I Mines Trans PF
20	2007	4	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	5	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	6	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	7	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	8	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	9	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	10	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2007	11	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF

Note: Formulas change half-way down the page!!!

Index	Year	Month	Class	Company	HDD60 (1)	HDD65 (2)	CDD65 (3)	CDD70 (4)	MinTemp (5)	MaxTemp (6)	Open (7)	Open (8)	Total Adjus	Class Descr
20	2007	12	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2008	1	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2008	2	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2008	3	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
20	2008	4	520	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Pri PF
21	2007	4	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	5	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	6	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	7	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	8	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	9	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	10	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	11	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2007	12	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2008	1	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2008	2	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2008	3	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
21	2008	4	530	KU	0	0	0	0	0	0	0	0	0	Lg C/I Mines LMP-TOD Trans PF
22	2007	4	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	5	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	6	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	7	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	8	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	9	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	10	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	11	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2007	12	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2008	1	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2008	2	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2008	3	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
22	2008	4	615	KU	0	0	0	0	0	0	0	0	0	Lg Ind LI-TOD Trans
23	2007	4	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2007	5	700	KU	0	0	0	0	0	-1063.92	0	0	-1063.92	Wholesale Municipal Pri
23	2007	6	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2007	7	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2007	8	700	KU	0	0	-2281.69	0	0	0	0	0	-2281.69	Wholesale Municipal Pri
23	2007	9	700	KU	0	-246.828	-1011.17	0	0	0	0	0	-1258	Wholesale Municipal Pri
23	2007	10	700	KU	0	0	-1690.67	0	0	0	0	0	-1690.67	Wholesale Municipal Pri
23	2007	11	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2007	12	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2008	1	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2008	2	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2008	3	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
23	2008	4	700	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Pri
24	2007	4	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2007	5	710	KU	0	0	-633.802	0	0	-1527.75	0	0	-2161.55	Wholesale Municipal Trans
24	2007	6	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2007	7	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2007	8	710	KU	0	0	0	-6024.94	0	0	0	0	-6024.94	Wholesale Municipal Trans
24	2007	9	710	KU	0	0	-2594.96	0	0	0	0	0	-2594.96	Wholesale Municipal Trans
24	2007	10	710	KU	0	0	-3689.38	0	0	0	0	0	-3689.38	Wholesale Municipal Trans
24	2007	11	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2007	12	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2008	1	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2008	2	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2008	3	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
24	2008	4	710	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Trans
25	2007	4	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	5	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	6	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	7	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	8	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	9	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	10	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	11	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2007	12	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2008	1	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2008	2	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2008	3	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
25	2008	4	720	KU	0	0	0	0	0	0	0	0	0	Wholesale Municipal Paris
26	2007	4	730	KU	-257.712	0	0	0	0	0	0	0	-257.712	Wholesale ODP - VA
26	2007	5	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2007	6	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2007	7	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2007	8	730	KU	0	0	0	0	-1183.18	0	0	0	-1183.18	Wholesale ODP - VA
26	2007	9	730	KU	0	0	0	-405.672	0	0	0	0	-405.672	Wholesale ODP - VA
26	2007	10	730	KU	0	0	-1510.82	0	1250.379	0	0	0	-260.439	Wholesale ODP - VA
26	2007	11	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2007	12	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2008	1	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2008	2	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2008	3	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
26	2008	4	730	KU	0	0	0	0	0	0	0	0	0	Wholesale ODP - VA
27	2007	4	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	5	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
27	2007	6	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	7	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	8	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	9	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	10	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	11	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2007	12	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2008	1	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2008	2	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2008	3	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
27	2008	4	Street Ligh	KU	0	0	0	0	0	0	0	0	0	Street Lighting
28	2007	4	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	5	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	6	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	7	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	8	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	9	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	10	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	11	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2007	12	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2008	1	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2008	2	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2008	3	800	KU	0	0	0	0	0	0	0	0	0	Company Use
28	2008	4	800	KU	0	0	0	0	0	0	0	0	0	Company Use
29	2007	4	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	5	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	6	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	7	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	8	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	9	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	10	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	11	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2007	12	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2008	1	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2008	2	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2008	3	Open	KU	0	0	0	0	0	0	0	0	0	Open
29	2008	4	Open	KU	0	0	0	0	0	0	0	0	0	Open
1	2007	4	1	LE	-1500 69	0	0	0	0	0	0	0	-1500.69	RS Sec
1	2007	5	1	LE	0	0	0	-4369 87	0	-6230 33	0	0	-10600.2	RS Sec
1	2007	6	1	LE	0	0	-6563 55	0	0	0	0	0	-6563.55	RS Sec
1	2007	7	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2007	8	1	LE	0	0	0	-73811 1	-14390 2	0	0	0	-88201 3	RS Sec
1	2007	9	1	LE	0	0	0	-34374 9	0	0	0	0	-34374.9	RS Sec
1	2007	10	1	LE	0	0	0	-37277 2	0	0	0	0	-37277.2	RS Sec
1	2007	11	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2007	12	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2008	1	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2008	2	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2008	3	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
1	2008	4	1	LE	0	0	0	0	0	0	0	0	0	RS Sec
2	2007	4	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2007	5	100	LE	0	0	-633 171	0	0	0	0	0	-633 171	C/I GS Sec 1 ph
2	2007	6	100	LE	0	0	-623 678	0	0	0	0	0	-623.678	C/I GS Sec 1 ph
2	2007	7	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2007	8	100	LE	0	0	0	-2689 78	0	0	0	0	-2689 78	C/I GS Sec 1 ph
2	2007	9	100	LE	0	0	-2391 06	0	0	0	0	0	-2391 06	C/I GS Sec 1 ph
2	2007	10	100	LE	0	0	-2349 79	0	0	0	0	0	-2349 79	C/I GS Sec 1 ph
2	2007	11	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2007	12	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2008	1	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2008	2	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2008	3	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
2	2008	4	100	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 1 ph
3	2007	4	105	LE	-140 91	0	0	0	0	0	0	0	-140 91	C/I GS Sec 3 ph
3	2007	5	105	LE	0	0	0	0	0	-1147 69	0	0	-1147 69	C/I GS Sec 3 ph
3	2007	6	105	LE	0	0	0	-585 51	0	0	0	0	-585.51	C/I GS Sec 3 ph
3	2007	7	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2007	8	105	LE	0	0	-7276 42	0	0	0	0	0	-7276.42	C/I GS Sec 3 ph
3	2007	9	105	LE	0	0	-3888 75	0	0	0	0	0	-3888.75	C/I GS Sec 3 ph
3	2007	10	105	LE	0	692 692	-4780 68	0	0	0	0	0	-4087 99	C/I GS Sec 3 ph
3	2007	11	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2007	12	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2008	1	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2008	2	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2008	3	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
3	2008	4	105	LE	0	0	0	0	0	0	0	0	0	C/I GS Sec 3 ph
4	2007	4	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	5	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	6	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	7	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	8	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	9	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	10	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	11	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2007	12	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph

Note: Formulas change half-way down the page!!!

Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
					1	2	3	4	5	6	7	8		
4	2008	1	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2008	2	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2008	3	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
4	2008	4	120	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 1 ph
5	2007	4	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	5	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	6	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	7	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	8	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	9	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	10	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	11	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2007	12	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2008	1	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2008	2	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2008	3	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
5	2008	4	125	LE	0	0	0	0	0	0	0	0	0	C/I GS Pri 3 ph
6	2007	4	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2007	5	200	LE	0	-32 8	-64 449	0	0	0	0	0	-97 249	C/I LC STOD Sec
6	2007	6	200	LE	0	0	0	-44 22	0	0	0	0	-44 22	C/I LC STOD Sec
6	2007	7	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2007	8	200	LE	0	0	-287 123	0	-201 574	0	0	0	-488.697	C/I LC STOD Sec
6	2007	9	200	LE	0	0	-142.416	0	-105.915	0	0	0	-248.331	C/I LC STOD Sec
6	2007	10	200	LE	0	-43 384	0	-228.54	-78 2502	0	0	0	-350 174	C/I LC STOD Sec
6	2007	11	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2007	12	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2008	1	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2008	2	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2008	3	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
6	2008	4	200	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Sec
7	2007	4	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2007	5	210	LE	0	0	-10 605	0	0	0	0	0	-10 605	C/I LC STOD Pri
7	2007	6	210	LE	0	0	-10 208	0	0	0	0	0	-10 208	C/I LC STOD Pri
7	2007	7	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2007	8	210	LE	0	0	-63 921	0	0	0	0	0	-63 921	C/I LC STOD Pri
7	2007	9	210	LE	0	0	0	0	-16 353	-20 475	0	0	-36.828	C/I LC STOD Pri
7	2007	10	210	LE	0	-5 06	-30 996	0	0	0	0	0	-36.056	C/I LC STOD Pri
7	2007	11	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2007	12	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2008	1	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2008	2	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2008	3	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
7	2008	4	210	LE	0	0	0	0	0	0	0	0	0	C/I LC STOD Pri
8	2007	4	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2007	5	220	LE	-135 894	0	-1469 92	0	0	0	0	0	-1605 81	C/I LC Sec
8	2007	6	220	LE	0	0	-1554.59	0	0	0	0	0	-1554 59	C/I LC Sec
8	2007	7	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2007	8	220	LE	0	0	0	-15641 7	0	4505 54	0	0	-11136.2	C/I LC Sec
8	2007	9	220	LE	0	0	-3793.29	0	-1639 85	0	0	0	-5433 14	C/I LC Sec
8	2007	10	220	LE	0	0	-5053	0	-2447 11	0	0	0	-7500 11	C/I LC Sec
8	2007	11	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2007	12	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2008	1	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2008	2	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2008	3	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
8	2008	4	220	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec
9	2007	4	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2007	5	230	LE	0	0	-134 862	0	0	0	0	0	-134 862	C/I LC Pri
9	2007	6	230	LE	0	0	-93 148	0	0	0	0	0	-93 148	C/I LC Pri
9	2007	7	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2007	8	230	LE	0	0	-559.346	0	-346.01	0	0	0	-905.356	C/I LC Pri
9	2007	9	230	LE	0	0	-235.382	0	-191 889	0	0	0	-427.271	C/I LC Pri
9	2007	10	230	LE	0	-136 224	-492 328	0	0	0	0	0	-628.552	C/I LC Pri
9	2007	11	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2007	12	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2008	1	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2008	2	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2008	3	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
9	2008	4	230	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri
10	2007	4	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2007	5	240	LE	0	0	-195 93	0	0	0	0	0	-195 93	C/I LC Sec TOD
10	2007	6	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2007	7	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2007	8	240	LE	0	0	-703 429	0	-555 222	0	0	0	-1258.65	C/I LC Sec TOD
10	2007	9	240	LE	0	0	-380 206	0	0	0	0	0	-380 206	C/I LC Sec TOD
10	2007	10	240	LE	0	-149 292	-597 452	0	0	0	0	0	-746.744	C/I LC Sec TOD
10	2007	11	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2007	12	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2008	1	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2008	2	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2008	3	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
10	2008	4	240	LE	0	0	0	0	0	0	0	0	0	C/I LC Sec TOD
11	2007	4	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2007	5	250	LE	0	0	-140.091	0	0	0	0	0	-140.091	C/I LC Pri TOD
11	2007	6	250	LE	0	0	-86 02	0	0	0	0	0	-86 02	C/I LC Pri TOD

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
11	2007	7	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2007	8	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2007	9	250	LE	0	0	0	0	-415 587	0	0	0	-415.587	C/I LC Pri TOD
11	2007	10	250	LE	0	0	-398 52	0	0	0	0	0	-398 52	C/I LC Pri TOD
11	2007	11	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2007	12	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2008	1	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2008	2	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2008	3	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
11	2008	4	250	LE	0	0	0	0	0	0	0	0	0	C/I LC Pri TOD
12	2007	4	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2007	5	260	LE	0	0	-85.365	0	0	0	0	0	-85.365	C/I LC Special
12	2007	6	260	LE	0	0	-55 77	0	0	0	0	0	-55 77	C/I LC Special
12	2007	7	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2007	8	260	LE	0	0	-610 602	0	0	0	0	0	-610 602	C/I LC Special
12	2007	9	260	LE	0	0	0	0	-269 928	0	0	0	-269.928	C/I LC Special
12	2007	10	260	LE	0	0	-232 88	0	0	0	0	0	-232 88	C/I LC Special
12	2007	11	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2007	12	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2008	1	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2008	2	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2008	3	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
12	2008	4	260	LE	0	0	0	0	0	0	0	0	0	C/I LC Special
13	2007	4	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2007	5	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2007	6	300	LE	0	0	0	-146 85	0	0	0	0	-146 85	C/I LP Sec
13	2007	7	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2007	8	300	LE	0	0	0	0	-970 374	0	0	0	-970 374	C/I LP Sec
13	2007	9	300	LE	0	376.194	0	0	-625 968	0	0	0	-249.774	C/I LP Sec
13	2007	10	300	LE	0	0	-681 83	0	-514 16	0	0	0	-1195 99	C/I LP Sec
13	2007	11	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2007	12	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2008	1	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2008	2	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2008	3	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
13	2008	4	300	LE	0	0	0	0	0	0	0	0	0	C/I LP Sec
14	2007	4	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2007	5	320	LE	0	-18 92	0	0	0	0	0	0	-18 92	C/I LP Pri
14	2007	6	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2007	7	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2007	8	320	LE	0	0	0	0	-158 522	0	0	0	-158 522	C/I LP Pri
14	2007	9	320	LE	0	0	0	0	-105 432	0	0	0	-105 432	C/I LP Pri
14	2007	10	320	LE	0	0	-163 754	0	0	0	0	0	-163 754	C/I LP Pri
14	2007	11	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2007	12	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2008	1	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2008	2	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2008	3	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
14	2008	4	320	LE	0	0	0	0	0	0	0	0	0	C/I LP Pri
15	2007	4	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	5	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	6	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	7	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	8	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	9	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	10	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	11	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2007	12	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2008	1	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2008	2	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2008	3	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
15	2008	4	400	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Sec TOD
16	2007	4	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	5	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	6	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	7	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	8	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	9	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	10	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	11	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2007	12	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2008	1	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2008	2	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2008	3	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
16	2008	4	420	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD
17	2007	4	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	5	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	6	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	7	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	8	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	9	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	10	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	11	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2007	12	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2008	1	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
17	2008	2	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2008	3	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
17	2008	4	430	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Pri TOD CSR
18	2007	4	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	5	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	6	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	7	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	8	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	9	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	10	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	11	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2007	12	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2008	1	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2008	2	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2008	3	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
18	2008	4	440	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD
19	2007	4	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	5	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	6	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	7	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	8	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	9	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	10	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	11	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2007	12	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2008	1	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2008	2	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2008	3	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
19	2008	4	450	LE	0	0	0	0	0	0	0	0	0	Lg C/I LP Trans TOD CSR
20	2007	4	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	5	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	6	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	7	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	8	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	9	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	10	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	11	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2007	12	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2008	1	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2008	2	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2008	3	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
20	2008	4	600	LE	0	0	0	0	0	0	0	0	0	Lg C/I Special
21	2007	4	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	5	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	6	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	7	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	8	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	9	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	10	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	11	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2007	12	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2008	1	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2008	2	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2008	3	800	LE	0	0	0	0	0	0	0	0	0	Company Use
21	2008	4	800	LE	0	0	0	0	0	0	0	0	0	Company Use
22	2007	4	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	5	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	6	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	7	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	8	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	9	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	10	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	11	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2007	12	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2008	1	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2008	2	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2008	3	Other OL	LE	0	0	0	0	0	0	0	0	0	700
22	2008	4	Other OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	4	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	5	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	6	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	7	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	8	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	9	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	10	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	11	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2007	12	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2008	1	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2008	2	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2008	3	RS OL	LE	0	0	0	0	0	0	0	0	0	700
23	2008	4	RS OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	4	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	5	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	6	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	7	Comm OL	LE	0	0	0	0	0	0	0	0	0	700

Note: Formulas change half-way down the page!!!

					1	2	3	4	5	6	7	8		
Index	Year	Month	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open	Total Adjus	Class Descr
24	2007	8	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	9	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	10	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	11	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2007	12	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2008	1	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2008	2	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2008	3	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
24	2008	4	Comm OL	LE	0	0	0	0	0	0	0	0	0	700
25	2007	4	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	5	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	6	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	7	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	8	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	9	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	10	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	11	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2007	12	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2008	1	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2008	2	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2008	3	PSL	LE	0	0	0	0	0	0	0	0	0	710
25	2008	4	PSL	LE	0	0	0	0	0	0	0	0	0	710
26	2007	4	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	5	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	6	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	7	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	8	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	9	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	10	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	11	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2007	12	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2008	1	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2008	2	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2008	3	SLE	LE	0	0	0	0	0	0	0	0	0	720
26	2008	4	SLE	LE	0	0	0	0	0	0	0	0	0	720
27	2007	4	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	5	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	6	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	7	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	8	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	9	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	10	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	11	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2007	12	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2008	1	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2008	2	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2008	3	TLE	LE	0	0	0	0	0	0	0	0	0	730
27	2008	4	TLE	LE	0	0	0	0	0	0	0	0	0	730
28	2007	4	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	5	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	6	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	7	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	8	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	9	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	10	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	11	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2007	12	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2008	1	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2008	2	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2008	3	Open	LE	0	0	0	0	0	0	0	0	0	Open
28	2008	4	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	4	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	5	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	6	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	7	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	8	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	9	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	10	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	11	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2007	12	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2008	1	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2008	2	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2008	3	Open	LE	0	0	0	0	0	0	0	0	0	Open
29	2008	4	Open	LE	0	0	0	0	0	0	0	0	0	Open

KU Normals

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev
2008_1_1	1	1/1/2008	HDD60	1	857	854	171	857
2008_2_1	1	2/1/2008	HDD60	2	705	683	145	705
2008_3_1	1	3/1/2008	HDD60	3	485	477	93	485
2007_4_1	1	4/1/2007	HDD60	4	274	205	63	268
2007_5_1	1	5/1/2007	HDD60	5	17	50	36	17
2007_6_1	1	6/1/2007	HDD60	6	0	0	0	0
2007_7_1	1	7/1/2007	HDD60	7	0	0	0	0
2007_8_1	1	8/1/2007	HDD60	8	0	0	0	0
2007_9_1	1	9/1/2007	HDD60	9	1	18	15	3
2007_10_1	1	10/1/2007	HDD60	10	91	166	60	106
2007_11_1	1	11/1/2007	HDD60	11	432	421	97	432
2007_12_1	1	12/1/2007	HDD60	12	610	734	155	610
2008_4_1	1	4/1/2008	HDD60	4	200	205	63	200
2008_1_2	2	1/1/2008	HDD65	1	1007	1008	171	1007
2008_2_2	2	2/1/2008	HDD65	2	849	823	145	849
2008_3_2	2	3/1/2008	HDD65	3	639	621	101	639
2007_4_2	2	4/1/2007	HDD65	4	377	318	76	377
2007_5_2	2	5/1/2007	HDD65	5	59	113	59	59
2007_6_2	2	6/1/2007	HDD65	6	0	0	0	0
2007_7_2	2	7/1/2007	HDD65	7	0	0	0	0
2007_8_2	2	8/1/2007	HDD65	8	0	0	0	0
2007_9_2	2	9/1/2007	HDD65	9	13	51	26	25
2007_10_2	2	10/1/2007	HDD65	10	164	278	76	202
2007_11_2	2	11/1/2007	HDD65	11	577	563	102	577
2007_12_2	2	12/1/2007	HDD65	12	765	887	158	765
2008_4_2	2	4/1/2008	HDD65	4	319	318	76	319
2008_1_3	3	1/1/2008	CDD65	1	0	0	0	0
2008_2_3	3	2/1/2008	CDD65	2	0	0	0	0
2008_3_3	3	3/1/2008	CDD65	3	0	0	0	0
2007_4_3	3	4/1/2007	CDD65	4	21	18	16	21
2007_5_3	3	5/1/2007	CDD65	5	155	85	51	136
2007_6_3	3	6/1/2007	CDD65	6	284	235	54	284
2007_7_3	3	7/1/2007	CDD65	7	309	354	64	309
2007_8_3	3	8/1/2007	CDD65	8	496	324	80	404
2007_9_3	3	9/1/2007	CDD65	9	238	146	55	201
2007_10_3	3	10/1/2007	CDD65	10	100	25	22	47
2007_11_3	3	11/1/2007	CDD65	11	0	0	0	0
2007_12_3	3	12/1/2007	CDD65	12	0	0	0	0
2008_4_3	3	4/1/2008	CDD65	4	14	18	16	14
2008_1_4	4	1/1/2008	CDD70	1	0	0	0	0
2008_2_4	4	2/1/2008	CDD70	2	0	0	0	0
2008_3_4	4	3/1/2008	CDD70	3	0	0	0	0
2007_4_4	4	4/1/2007	CDD70	4	2	2	5	2
2007_5_4	4	5/1/2007	CDD70	5	64	27	25	52
2007_6_4	4	6/1/2007	CDD70	6	148	116	42	148
2007_7_4	4	7/1/2007	CDD70	7	157	204	61	157
2007_8_4	4	8/1/2007	CDD70	8	341	180	72	252
2007_9_4	4	9/1/2007	CDD70	9	124	63	37	100
2007_10_4	4	10/1/2007	CDD70	10	44	5	9	14

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Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev
2007_11_4	4	11/1/2007	CDD70	11	0	0	0	0
2007_12_4	4	12/1/2007	CDD70	12	0	0	0	0
2008_4_4	4	4/1/2008	CDD70	4	3	2	5	3
2008_1_5	5	1/1/2008	MinTemp	1	745	759.5	167.4	745
2008_2_5	5	2/1/2008	MinTemp	2	805	762.75	141.25	805
2008_3_5	5	3/1/2008	MinTemp	3	1058	1091.2	93	1058
2007_4_5	5	4/1/2007	MinTemp	4	1290	1335	84	1290
2007_5_5	5	5/1/2007	MinTemp	5	1736	1674	102.3	1736
2007_6_5	5	6/1/2007	MinTemp	6	1920	1872	54	1920
2007_7_5	5	7/1/2007	MinTemp	7	1984	2064.6	55.8	2008.8
2007_8_5	5	8/1/2007	MinTemp	8	2139	2027.4	74.4	2101.8
2007_9_5	5	9/1/2007	MinTemp	9	1800	1731	69	1800
2007_10_5	5	10/1/2007	MinTemp	10	1612	1438.4	105.4	1543.8
2007_11_5	5	11/1/2007	MinTemp	11	1080	1119	99	1080
2007_12_5	5	12/1/2007	MinTemp	12	992	877.3	155	992
2008_4_5	5	4/1/2008	MinTemp	4	1330	1335	84	1330
2008_1_6	6	1/1/2008	MaxTemp	1	1256	1252.4	179.8	1256
2008_2_6	6	2/1/2008	MaxTemp	2	1254	1259.95	155.375	1254
2008_3_6	6	3/1/2008	MaxTemp	3	1676	1701.9	117.8	1676
2007_4_6	6	4/1/2007	MaxTemp	4	1890	1962	93	1890
2007_5_6	6	5/1/2007	MaxTemp	5	2480	2300.2	111.6	2411.8
2007_6_6	6	6/1/2007	MaxTemp	6	2550	2478	78	2550
2007_7_6	6	7/1/2007	MaxTemp	7	2635	2672.2	80.6	2635
2007_8_6	6	8/1/2007	MaxTemp	8	2852	2647.4	99.2	2746.6
2007_9_6	6	9/1/2007	MaxTemp	9	2520	2358	96	2454
2007_10_6	6	10/1/2007	MaxTemp	10	2263	2086.3	80.6	2166.9
2007_11_6	6	11/1/2007	MaxTemp	11	1650	1659	117	1650
2007_12_6	6	12/1/2007	MaxTemp	12	1488	1376.4	164.3	1488
2008_4_6	6	4/1/2008	MaxTemp	4	1943	1962	93	1943
2008_1_7	7	1/1/2008	Open	1	0	0	0	0
2008_2_7	7	2/1/2008	Open	2	0	0	0	0
2008_3_7	7	3/1/2008	Open	3	0	0	0	0
2007_4_7	7	4/1/2007	Open	4	0	0	0	0
2007_5_7	7	5/1/2007	Open	5	0	0	0	0
2007_6_7	7	6/1/2007	Open	6	0	0	0	0
2007_7_7	7	7/1/2007	Open	7	0	0	0	0
2007_8_7	7	8/1/2007	Open	8	0	0	0	0
2007_9_7	7	9/1/2007	Open	9	0	0	0	0
2007_10_7	7	10/1/2007	Open	10	0	0	0	0
2007_11_7	7	11/1/2007	Open	11	0	0	0	0
2007_12_7	7	12/1/2007	Open	12	0	0	0	0
2008_4_7	7	4/1/2008	Open	4	0	0	0	0
2008_1_8	8	1/1/2008	Open	1	0	0	0	0
2008_2_8	8	2/1/2008	Open	2	0	0	0	0
2008_3_8	8	3/1/2008	Open	3	0	0	0	0
2007_4_8	8	4/1/2007	Open	4	0	0	0	0
2007_5_8	8	5/1/2007	Open	5	0	0	0	0
2007_6_8	8	6/1/2007	Open	6	0	0	0	0
2007_7_8	8	7/1/2007	Open	7	0	0	0	0

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Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev	
2007_8_8	8	8/1/2007	Open	8	0	0	0	0	
2007_9_8	8	9/1/2007	Open	9	0	0	0	0	
2007_10_8	8	10/1/2007	Open	10	0	0	0	0	
2007_11_8	8	11/1/2007	Open	11	0	0	0	0	
2007_12_8	8	12/1/2007	Open	12	0	0	0	0	
2008_4_8	8	4/1/2008	Open	4	0	0	0	0	

KU Normals

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2008_1_1	HDD60	1	790	854	0	152	171	0
2008_2_1	HDD60	2	648	683	0	115	145	0
2008_3_1	HDD60	3	473	477	0	93	93	0
2007_4_1	HDD60	4	203	205	0	63	63	0
2007_5_1	HDD60	5	48	50	0	36	36	0
2007_6_1	HDD60	6	0	0	0	0	0	0
2007_7_1	HDD60	7	0	0	0	0	0	0
2007_8_1	HDD60	8	0	0	0	0	0	0
2007_9_1	HDD60	9	18	18	0	15	15	0
2007_10_1	HDD60	10	169	166	0	57	60	0
2007_11_1	HDD60	11	427	421	0	104	97	0
2007_12_1	HDD60	12	737	734	0	155	155	0
2008_4_1	HDD60	4	203	205	0	63	63	0
2008_1_2	HDD65	1	945	1008	0	152	171	0
2008_2_2	HDD65	2	788	823	0	116	145	0
2008_3_2	HDD65	3	616	621	0	102	101	0
2007_4_2	HDD65	4	314	318	0	73	76	0
2007_5_2	HDD65	5	112	113	0	60	59	0
2007_6_2	HDD65	6	0	0	0	0	0	0
2007_7_2	HDD65	7	0	0	0	0	0	0
2007_8_2	HDD65	8	0	0	0	0	0	0
2007_9_2	HDD65	9	52	51	0	26	26	0
2007_10_2	HDD65	10	280	278	0	66	76	0
2007_11_2	HDD65	11	570	563	0	107	102	0
2007_12_2	HDD65	12	891	887	0	155	158	0
2008_4_2	HDD65	4	314	318	0	73	76	0
2008_1_3	CDD65	1	0	0	0	0	0	0
2008_2_3	CDD65	2	0	0	0	0	0	0
2008_3_3	CDD65	3	0	0	0	0	0	0
2007_4_3	CDD65	4	19	18	0	18	16	0
2007_5_3	CDD65	5	85	85	0	49	51	0
2007_6_3	CDD65	6	235	235	0	51	54	0
2007_7_3	CDD65	7	352	354	0	64	64	0
2007_8_3	CDD65	8	328	324	0	81	80	0
2007_9_3	CDD65	9	141	146	0	61	55	0
2007_10_3	CDD65	10	25	25	0	23	22	0
2007_11_3	CDD65	11	0	0	0	0	0	0
2007_12_3	CDD65	12	0	0	0	0	0	0
2008_4_3	CDD65	4	19	18	0	18	16	0
2008_1_4	CDD70	1	0	0	0	0	0	0
2008_2_4	CDD70	2	0	0	0	0	0	0
2008_3_4	CDD70	3	0	0	0	0	0	0
2007_4_4	CDD70	4	3	2	0	6	5	0
2007_5_4	CDD70	5	27	27	0	23	25	0
2007_6_4	CDD70	6	116	116	0	40	42	0
2007_7_4	CDD70	7	202	204	0	61	61	0
2007_8_4	CDD70	8	184	180	0	71	72	0
2007_9_4	CDD70	9	59	63	0	39	37	0
2007_10_4	CDD70	10	6	5	0	10	9	0

KU Normals

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2007_11_4	CDD70	11	0	0	0	0	0	0
2007_12_4	CDD70	12	0	0	0	0	0	0
2008_4_4	CDD70	4	3	2	0	6	5	0
2008_1_5	MinTemp	1	818.4	759.5	0	151.9	167.4	0
2008_2_5	MinTemp	2	796.65	762.75	0	113	141.25	0
2008_3_5	MinTemp	3	1094.3	1091.2	0	96.1	93	0
2007_4_5	MinTemp	4	1338	1335	0	90	84	0
2007_5_5	MinTemp	5	1674	1674	0	102.3	102.3	0
2007_6_5	MinTemp	6	1872	1872	0	48	54	0
2007_7_5	MinTemp	7	2064.6	2064.6	0	52.7	55.8	0
2007_8_5	MinTemp	8	2027.4	2027.4	0	74.4	74.4	0
2007_9_5	MinTemp	9	1725	1731	0	66	69	0
2007_10_5	MinTemp	10	1435.3	1438.4	0	83.7	105.4	0
2007_11_5	MinTemp	11	1107	1119	0	93	99	0
2007_12_5	MinTemp	12	877.3	877.3	0	145.7	155	0
2008_4_5	MinTemp	4	1338	1335	0	90	84	0
2008_1_6	MaxTemp	1	1323.7	1252.4	0	158.1	179.8	0
2008_2_6	MaxTemp	2	1299.5	1259.95	0	124.3	155.375	0
2008_3_6	MaxTemp	3	1708.1	1701.9	0	117.8	117.8	0
2007_4_6	MaxTemp	4	1971	1962	0	84	93	0
2007_5_6	MaxTemp	5	2300.2	2300.2	0	105.4	111.6	0
2007_6_6	MaxTemp	6	2475	2478	0	84	78	0
2007_7_6	MaxTemp	7	2672.2	2672.2	0	80.6	80.6	0
2007_8_6	MaxTemp	8	2656.7	2647.4	0	99.2	99.2	0
2007_9_6	MaxTemp	9	2352	2358	0	105	96	0
2007_10_6	MaxTemp	10	2086.3	2086.3	0	83.7	80.6	0
2007_11_6	MaxTemp	11	1653	1659	0	129	117	0
2007_12_6	MaxTemp	12	1370.2	1376.4	0	164.3	164.3	0
2008_4_6	MaxTemp	4	1971	1962	0	84	93	0
2008_1_7	Open	1	0	0	0	0	0	0
2008_2_7	Open	2	0	0	0	0	0	0
2008_3_7	Open	3	0	0	0	0	0	0
2007_4_7	Open	4	0	0	0	0	0	0
2007_5_7	Open	5	0	0	0	0	0	0
2007_6_7	Open	6	0	0	0	0	0	0
2007_7_7	Open	7	0	0	0	0	0	0
2007_8_7	Open	8	0	0	0	0	0	0
2007_9_7	Open	9	0	0	0	0	0	0
2007_10_7	Open	10	0	0	0	0	0	0
2007_11_7	Open	11	0	0	0	0	0	0
2007_12_7	Open	12	0	0	0	0	0	0
2008_4_7	Open	4	0	0	0	0	0	0
2008_1_8	Open	1	0	0	0	0	0	0
2008_2_8	Open	2	0	0	0	0	0	0
2008_3_8	Open	3	0	0	0	0	0	0
2007_4_8	Open	4	0	0	0	0	0	0
2007_5_8	Open	5	0	0	0	0	0	0
2007_6_8	Open	6	0	0	0	0	0	0
2007_7_8	Open	7	0	0	0	0	0	0

KU Normals

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2007_8_8	Open	8	0	0	0	0	0	0
2007_9_8	Open	9	0	0	0	0	0	0
2007_10_8	Open	10	0	0	0	0	0	0
2007_11_8	Open	11	0	0	0	0	0	0
2007_12_8	Open	12	0	0	0	0	0	0
2008_4_8	Open	4	0	0	0	0	0	0

LE Normals

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev
2008_1_1	1	1/1/2008	HDD60	1	786	809	171	786
2008_2_1	1	2/1/2008	HDD60	2	646	638	144	646
2008_3_1	1	3/1/2008	HDD60	3	417	426	94	417
2007_4_1	1	4/1/2007	HDD60	4	236	163	59	222
2007_5_1	1	5/1/2007	HDD60	5	4	29	24	5
2007_6_1	1	6/1/2007	HDD60	6	0	0	0	0
2007_7_1	1	7/1/2007	HDD60	7	0	0	0	0
2007_8_1	1	8/1/2007	HDD60	8	0	0	0	0
2007_9_1	1	9/1/2007	HDD60	9	0	10	11	0
2007_10_1	1	10/1/2007	HDD60	10	48	127	55	72
2007_11_1	1	11/1/2007	HDD60	11	348	370	94	348
2007_12_1	1	12/1/2007	HDD60	12	557	689	155	557
2008_4_1	1	4/1/2008	HDD60	4	144	163	59	144
2008_1_2	2	1/1/2008	HDD65	1	935	963	171	935
2008_2_2	2	2/1/2008	HDD65	2	787	778	145	787
2008_3_2	2	3/1/2008	HDD65	3	569	567	103	569
2007_4_2	2	4/1/2007	HDD65	4	329	265	74	329
2007_5_2	2	5/1/2007	HDD65	5	27	78	46	32
2007_6_2	2	6/1/2007	HDD65	6	0	5	6	0
2007_7_2	2	7/1/2007	HDD65	7	0	0	0	0
2007_8_2	2	8/1/2007	HDD65	8	0	0	0	0
2007_9_2	2	9/1/2007	HDD65	9	3	33	23	10
2007_10_2	2	10/1/2007	HDD65	10	114	230	72	158
2007_11_2	2	11/1/2007	HDD65	11	484	509	100	484
2007_12_2	2	12/1/2007	HDD65	12	712	841	157	712
2008_4_2	2	4/1/2008	HDD65	4	240	265	74	240
2008_1_3	3	1/1/2008	CDD65	1	0	0	0	0
2008_2_3	3	2/1/2008	CDD65	2	0	0	0	0
2008_3_3	3	3/1/2008	CDD65	3	0	0	0	0
2007_4_3	3	4/1/2007	CDD65	4	51	29	24	51
2007_5_3	3	5/1/2007	CDD65	5	202	120	61	181
2007_6_3	3	6/1/2007	CDD65	6	382	299	61	360
2007_7_3	3	7/1/2007	CDD65	7	397	429	60	397
2007_8_3	3	8/1/2007	CDD65	8	629	399	81	480
2007_9_3	3	9/1/2007	CDD65	9	350	198	66	264
2007_10_3	3	10/1/2007	CDD65	10	149	37	30	67
2007_11_3	3	11/1/2007	CDD65	11	0	0	0	0
2007_12_3	3	12/1/2007	CDD65	12	0	0	0	0
2008_4_3	3	4/1/2008	CDD65	4	30	29	24	30
2008_1_4	4	1/1/2008	CDD70	1	0	0	0	0
2008_2_4	4	2/1/2008	CDD70	2	0	0	0	0
2008_3_4	4	3/1/2008	CDD70	3	0	0	0	0
2007_4_4	4	4/1/2007	CDD70	4	11	7	11	11
2007_5_4	4	5/1/2007	CDD70	5	96	47	37	84
2007_6_4	4	6/1/2007	CDD70	6	232	167	50	217
2007_7_4	4	7/1/2007	CDD70	7	242	276	59	242
2007_8_4	4	8/1/2007	CDD70	8	474	249	81	330
2007_9_4	4	9/1/2007	CDD70	9	212	98	49	147

LE Normals

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev
2007_10_4	4	10/1/2007	CDD70	10	78	11	15	26
2007_11_4	4	11/1/2007	CDD70	11	0	0	0	0
2007_12_4	4	12/1/2007	CDD70	12	0	0	0	0
2008_4_4	4	4/1/2008	CDD70	4	6	7	11	6
2008_1_5	5	1/1/2008	MinTemp	1	827	806	167 4	827
2008_2_5	5	2/1/2008	MinTemp	2	878	807 95	141 25	878
2008_3_5	5	3/1/2008	MinTemp	3	1147	1147	99 2	1147
2007_4_5	5	4/1/2007	MinTemp	4	1380	1395	90	1380
2007_5_5	5	5/1/2007	MinTemp	5	1860	1745 3	102 3	1847 6
2007_6_5	5	6/1/2007	MinTemp	6	2040	1953	66	2019
2007_7_5	5	7/1/2007	MinTemp	7	2108	2154.5	55 8	2108
2007_8_5	5	8/1/2007	MinTemp	8	2294	2114 2	80.6	2194.8
2007_9_5	5	9/1/2007	MinTemp	9	1950	1806	75	1881
2007_10_5	5	10/1/2007	MinTemp	10	1736	1494 2	111 6	1605.8
2007_11_5	5	11/1/2007	MinTemp	11	1170	1173	96	1170
2007_12_5	5	12/1/2007	MinTemp	12	1054	930	158 1	1054
2008_4_5	5	4/1/2008	MinTemp	4	1417	1395	90	1417
2008_1_6	6	1/1/2008	MaxTemp	1	1325	1298.9	179 8	1325
2008_2_6	6	2/1/2008	MaxTemp	2	1305	1307 975	155 375	1305
2008_3_6	6	3/1/2008	MaxTemp	3	1735	1760.8	124	1735
2007_4_6	6	4/1/2007	MaxTemp	4	1950	2031	99	1950
2007_5_6	6	5/1/2007	MaxTemp	5	2511	2368 4	105 4	2473 8
2007_6_6	6	6/1/2007	MaxTemp	6	2610	2532	81	2610
2007_7_6	6	7/1/2007	MaxTemp	7	2728	2734 2	74 4	2728
2007_8_6	6	8/1/2007	MaxTemp	8	2976	2712 5	102.3	2814 8
2007_9_6	6	9/1/2007	MaxTemp	9	2640	2424	99	2523
2007_10_6	6	10/1/2007	MaxTemp	10	2325	2148 3	80 6	2228.9
2007_11_6	6	11/1/2007	MaxTemp	11	1740	1713	123	1740
2007_12_6	6	12/1/2007	MaxTemp	12	1550	1416 7	164.3	1550
2008_4_6	6	4/1/2008	MaxTemp	4	2050	2031	99	2050
2008_1_7	7	1/1/2008	Open	1	0	0	0	0
2008_2_7	7	2/1/2008	Open	2	0	0	0	0
2008_3_7	7	3/1/2008	Open	3	0	0	0	0
2007_4_7	7	4/1/2007	Open	4	0	0	0	0
2007_5_7	7	5/1/2007	Open	5	0	0	0	0
2007_6_7	7	6/1/2007	Open	6	0	0	0	0
2007_7_7	7	7/1/2007	Open	7	0	0	0	0
2007_8_7	7	8/1/2007	Open	8	0	0	0	0
2007_9_7	7	9/1/2007	Open	9	0	0	0	0
2007_10_7	7	10/1/2007	Open	10	0	0	0	0
2007_11_7	7	11/1/2007	Open	11	0	0	0	0
2007_12_7	7	12/1/2007	Open	12	0	0	0	0
2008_4_7	7	4/1/2008	Open	4	0	0	0	0
2008_1_8	8	1/1/2008	Open	1	0	0	0	0
2008_2_8	8	2/1/2008	Open	2	0	0	0	0
2008_3_8	8	3/1/2008	Open	3	0	0	0	0
2007_4_8	8	4/1/2007	Open	4	0	0	0	0
2007_5_8	8	5/1/2007	Open	5	0	0	0	0

LE Normals

Lookup	Index	Calendar Month	Variable	Month	Actual	Normal	Stdev	Normal +/- Stdev
2007_6_8	8	6/1/2007	Open	6	0	0	0	0
2007_7_8	8	7/1/2007	Open	7	0	0	0	0
2007_8_8	8	8/1/2007	Open	8	0	0	0	0
2007_9_8	8	9/1/2007	Open	9	0	0	0	0
2007_10_8	8	10/1/2007	Open	10	0	0	0	0
2007_11_8	8	11/1/2007	Open	11	0	0	0	0
2007_12_8	8	12/1/2007	Open	12	0	0	0	0
2008_4_8	8	4/1/2008	Open	4	0	0	0	0

LE Normals

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2008_1_1	HDD60	1	743	809	0	150	171	0
2008_2_1	HDD60	2	598	638	0	117	144	0
2008_3_1	HDD60	3	411	426	0	92	94	0
2007_4_1	HDD60	4	154	163	0	53	59	0
2007_5_1	HDD60	5	26	29	0	23	24	0
2007_6_1	HDD60	6	0	0	0	0	0	0
2007_7_1	HDD60	7	0	0	0	0	0	0
2007_8_1	HDD60	8	0	0	0	0	0	0
2007_9_1	HDD60	9	10	10	0	10	11	0
2007_10_1	HDD60	10	123	127	0	54	55	0
2007_11_1	HDD60	11	370	370	0	105	94	0
2007_12_1	HDD60	12	686	689	0	151	155	0
2008_4_1	HDD60	4	154	163	0	53	59	0
2008_1_2	HDD65	1	896	963	0	150	171	0
2008_2_2	HDD65	2	738	778	0	118	145	0
2008_3_2	HDD65	3	552	567	0	102	103	0
2007_4_2	HDD65	4	253	265	0	64	74	0
2007_5_2	HDD65	5	73	78	0	45	46	0
2007_6_2	HDD65	6	6	5	0	7	6	0
2007_7_2	HDD65	7	0	0	0	0	0	0
2007_8_2	HDD65	8	0	0	0	0	0	0
2007_9_2	HDD65	9	31	33	0	21	23	0
2007_10_2	HDD65	10	223	230	0	67	72	0
2007_11_2	HDD65	11	508	509	0	110	100	0
2007_12_2	HDD65	12	640	841	0	152	157	0
2008_4_2	HDD65	4	253	265	0	64	74	0
2008_1_3	CDD65	1	0	0	0	0	0	0
2008_2_3	CDD65	2	0	0	0	0	0	0
2008_3_3	CDD65	3	0	0	0	0	0	0
2007_4_3	CDD65	4	32	29	0	25	24	0
2007_5_3	CDD65	5	124	120	0	64	61	0
2007_6_3	CDD65	6	306	299	0	57	61	0
2007_7_3	CDD65	7	435	429	0	57	60	0
2007_8_3	CDD65	8	414	399	0	85	81	0
2007_9_3	CDD65	9	199	198	0	72	66	0
2007_10_3	CDD65	10	39	37	0	33	30	0
2007_11_3	CDD65	11	0	0	0	0	0	0
2007_12_3	CDD65	12	0	0	0	0	0	0
2008_4_3	CDD65	4	32	29	0	25	24	0
2008_1_4	CDD70	1	0	0	0	0	0	0
2008_2_4	CDD70	2	0	0	0	0	0	0
2008_3_4	CDD70	3	0	0	0	0	0	0
2007_4_4	CDD70	4	9	7	0	12	11	0
2007_5_4	CDD70	5	51	47	0	40	37	0
2007_6_4	CDD70	6	174	167	0	48	50	0
2007_7_4	CDD70	7	281	276	0	57	59	0
2007_8_4	CDD70	8	263	249	0	80	81	0
2007_9_4	CDD70	9	99	98	0	53	49	0

LE Normal:

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2007_10_4	CDD70	10	12	11	0	18	15	0
2007_11_4	CDD70	11	0	0	0	0	0	0
2007_12_4	CDD70	12	0	0	0	0	0	0
2008_4_4	CDD70	4	9	7	0	12	11	0
2008_1_5	MinTemp	1	871.1	806	0	158.1	167.4	0
2008_2_5	MinTemp	2	847.5	807.95	0	115.825	141.25	0
2008_3_5	MinTemp	3	1165.6	1147	0	102.3	99.2	0
2007_4_5	MinTemp	4	1410	1395	0	87	90	0
2007_5_5	MinTemp	5	1760.8	1745.3	0	108.5	102.3	0
2007_6_5	MinTemp	6	1965	1953	0	60	66	0
2007_7_5	MinTemp	7	2163.8	2154.5	0	52.7	55.8	0
2007_8_5	MinTemp	8	2126.6	2114.2	0	80.6	80.6	0
2007_9_5	MinTemp	9	1812	1806	0	75	75	0
2007_10_5	MinTemp	10	1506.6	1494.2	0	96.1	111.6	0
2007_11_5	MinTemp	11	1173	1173	0	96	96	0
2007_12_5	MinTemp	12	936.2	930	0	155	158.1	0
2008_4_5	MinTemp	4	1410	1395	0	87	90	0
2008_1_6	MaxTemp	1	1376.4	1298.9	0	158.1	179.8	0
2008_2_6	MaxTemp	2	1347.525	1307.975	0	127.125	155.375	0
2008_3_6	MaxTemp	3	1776.3	1760.8	0	124	124	0
2007_4_6	MaxTemp	4	2046	2031	0	81	99	0
2007_5_6	MaxTemp	5	2371.5	2368.4	0	99.2	105.4	0
2007_6_6	MaxTemp	6	2535	2532	0	84	81	0
2007_7_6	MaxTemp	7	2737.3	2734.2	0	71.3	74.4	0
2007_8_6	MaxTemp	8	2728	2712.5	0	99.2	102.3	0
2007_9_6	MaxTemp	9	2424	2424	0	108	99	0
2007_10_6	MaxTemp	10	2157.6	2148.3	0	86.8	80.6	0
2007_11_6	MaxTemp	11	1713	1713	0	138	123	0
2007_12_6	MaxTemp	12	1413.6	1416.7	0	158.1	164.3	0
2008_4_6	MaxTemp	4	2046	2031	0	81	99	0
2008_1_7	Open	1	0	0	0	0	0	0
2008_2_7	Open	2	0	0	0	0	0	0
2008_3_7	Open	3	0	0	0	0	0	0
2007_4_7	Open	4	0	0	0	0	0	0
2007_5_7	Open	5	0	0	0	0	0	0
2007_6_7	Open	6	0	0	0	0	0	0
2007_7_7	Open	7	0	0	0	0	0	0
2007_8_7	Open	8	0	0	0	0	0	0
2007_9_7	Open	9	0	0	0	0	0	0
2007_10_7	Open	10	0	0	0	0	0	0
2007_11_7	Open	11	0	0	0	0	0	0
2007_12_7	Open	12	0	0	0	0	0	0
2008_4_7	Open	4	0	0	0	0	0	0
2008_1_8	Open	1	0	0	0	0	0	0
2008_2_8	Open	2	0	0	0	0	0	0
2008_3_8	Open	3	0	0	0	0	0	0
2007_4_8	Open	4	0	0	0	0	0	0
2007_5_8	Open	5	0	0	0	0	0	0

LE Normal:

Lookup	Variable	Month	20-Year Normal	30-Year Normal	OPEN	20-Year Stdev	30-Year Stdev	OPEN
2007_6_8	Open	6	0	0	0	0	0	0
2007_7_8	Open	7	0	0	0	0	0	0
2007_8_8	Open	8	0	0	0	0	0	0
2007_9_8	Open	9	0	0	0	0	0	0
2007_10_8	Open	10	0	0	0	0	0	0
2007_11_8	Open	11	0	0	0	0	0	0
2007_12_8	Open	12	0	0	0	0	0	0
2008_4_8	Open	4	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
1	2007	4	2007_4_1	1	KU	85984	0	189665	0	0	0	0	0
1	2007	5	2007_5_1	1	KU	0	0	0	459125	0	124360	0	0
1	2007	6	2007_6_1	1	KU	0	0	158238	0	0	116465	0	0
1	2007	7	2007_7_1	1	KU	0	0	0	212068	0	129398	0	0
1	2007	8	2007_8_1	1	KU	0	0	0	391299	0	0	0	0
1	2007	9	2007_9_1	1	KU	0	0	348180	0	0	0	0	0
1	2007	10	2007_10_1	1	KU	0	0	296993	0	0	0	0	0
1	2007	11	2007_11_1	1	KU	97271	0	0	0	0	0	0	0
1	2007	12	2007_12_1	1	KU	0	0	0	0	-97910	0	0	0
1	2008	1	2008_1_1	1	KU	131167	0	0	0	0	0	0	0
1	2008	2	2008_2_1	1	KU	0	138295	0	0	0	0	0	0
1	2008	3	2008_3_1	1	KU	123508	0	0	0	0	0	0	0
1	2008	4	2008_4_1	1	KU	58061	0	0	0	51313	0	0	0
2	2007	4	2007_4_2	20	KU	0	236242	0	0	0	0	0	0
2	2007	5	2007_5_2	20	KU	0	0	0	264049	0	48566	0	0
2	2007	6	2007_6_2	20	KU	0	0	176387	0	0	0	0	0
2	2007	7	2007_7_2	20	KU	0	0	0	234869	0	0	0	0
2	2007	8	2007_8_2	20	KU	0	0	218745	0	0	0	0	0
2	2007	9	2007_9_2	20	KU	0	0	222786	0	0	0	0	0
2	2007	10	2007_10_2	20	KU	0	0	0	329137	-40369	0	0	0
2	2007	11	2007_11_2	20	KU	285527	0	0	0	0	0	0	0
2	2007	12	2007_12_2	20	KU	0	0	0	0	-335662	0	0	0
2	2008	1	2008_1_2	20	KU	393679	0	0	0	0	0	0	0
2	2008	2	2008_2_2	20	KU	363481	0	0	0	0	0	0	0
2	2008	3	2008_3_2	20	KU	344541	0	0	0	0	0	0	0
2	2008	4	2008_4_2	20	KU	190695	0	0	0	0	0	0	0
3	2007	4	2007_4_3	100	KU	0	0	249562	0	0	0	0	0
3	2007	5	2007_5_3	100	KU	0	0	0	0	0	37834	0	0
3	2007	6	2007_6_3	100	KU	0	0	0	0	0	38202	0	0
3	2007	7	2007_7_3	100	KU	0	0	0	70989	0	0	0	0
3	2007	8	2007_8_3	100	KU	0	0	62898	0	0	0	0	0
3	2007	9	2007_9_3	100	KU	0	0	70440	0	0	0	0	0
3	2007	10	2007_10_3	100	KU	0	0	73464	0	0	0	0	0
3	2007	11	2007_11_3	100	KU	0	0	0	0	0	0	0	0
3	2007	12	2007_12_3	100	KU	0	33243	0	0	0	0	0	0
3	2008	1	2008_1_3	100	KU	0	25612	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
3	2008	2	2008_2_3	100	KU	0	0	0	0	0	-19113	0	0
3	2008	3	2008_3_3	100	KU	29218	0	0	0	0	0	0	0
3	2008	4	2008_4_3	100	KU	0	0	58798	0	0	0	0	0
4	2007	4	2007_4_4	120	KU	0	0	0	0	0	0	0	0
4	2007	5	2007_5_4	120	KU	0	0	0	0	0	0	0	0
4	2007	6	2007_6_4	120	KU	0	0	0	0	0	0	0	0
4	2007	7	2007_7_4	120	KU	0	0	0	0	0	0	0	0
4	2007	8	2007_8_4	120	KU	0	0	0	0	0	0	0	0
4	2007	9	2007_9_4	120	KU	0	0	0	0	0	0	0	0
4	2007	10	2007_10_4	120	KU	0	0	0	0	0	0	0	0
4	2007	11	2007_11_4	120	KU	0	0	0	0	0	0	0	0
4	2007	12	2007_12_4	120	KU	0	0	0	0	0	0	0	0
4	2008	1	2008_1_4	120	KU	0	0	0	0	0	0	0	0
4	2008	2	2008_2_4	120	KU	0	0	0	0	0	0	0	0
4	2008	3	2008_3_4	120	KU	0	0	0	0	0	0	0	0
4	2008	4	2008_4_4	120	KU	0	0	0	0	0	0	0	0
5	2007	4	2007_4_5	140	KU	0	0	0	0	0	0	0	0
5	2007	5	2007_5_5	140	KU	0	0	0	0	0	0	0	0
5	2007	6	2007_6_5	140	KU	0	0	0	0	0	0	0	0
5	2007	7	2007_7_5	140	KU	0	0	0	0	0	0	0	0
5	2007	8	2007_8_5	140	KU	0	0	0	0	0	0	0	0
5	2007	9	2007_9_5	140	KU	0	0	0	0	0	0	0	0
5	2007	10	2007_10_5	140	KU	0	0	0	0	0	0	0	0
5	2007	11	2007_11_5	140	KU	0	0	0	0	0	0	0	0
5	2007	12	2007_12_5	140	KU	0	0	0	0	0	0	0	0
5	2008	1	2008_1_5	140	KU	0	0	0	0	0	0	0	0
5	2008	2	2008_2_5	140	KU	0	0	0	0	0	0	0	0
5	2008	3	2008_3_5	140	KU	0	0	0	0	0	0	0	0
5	2008	4	2008_4_5	140	KU	0	0	0	0	0	0	0	0
6	2007	4	2007_4_6	160	KU	0	0	0	0	0	0	0	0
6	2007	5	2007_5_6	160	KU	0	0	0	0	0	0	0	0
6	2007	6	2007_6_6	160	KU	0	0	0	0	0	0	0	0
6	2007	7	2007_7_6	160	KU	0	0	0	0	0	0	0	0
6	2007	8	2007_8_6	160	KU	0	0	0	0	0	0	0	0
6	2007	9	2007_9_6	160	KU	0	0	0	0	0	0	0	0
6	2007	10	2007_10_6	160	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
6	2007	11	2007_11_6	160	KU	0	0	0	0	0	0	0	0
6	2007	12	2007_12_6	160	KU	0	0	0	0	0	0	0	0
6	2008	1	2008_1_6	160	KU	0	0	0	0	0	0	0	0
6	2008	2	2008_2_6	160	KU	0	0	0	0	0	0	0	0
6	2008	3	2008_3_6	160	KU	0	0	0	0	0	0	0	0
6	2008	4	2008_4_6	160	KU	0	0	0	0	0	0	0	0
7	2007	4	2007_4_7	200	KU	0	0	4307	0	1446	0	0	0
7	2007	5	2007_5_7	200	KU	0	0	2591	0	0	1266	0	0
7	2007	6	2007_6_7	200	KU	0	0	0	0	0	2753	0	0
7	2007	7	2007_7_7	200	KU	0	0	4924	0	0	0	0	0
7	2007	8	2007_8_7	200	KU	0	0	0	0	1539	2424	0	0
7	2007	9	2007_9_7	200	KU	0	0	0	2896	0	803	0	0
7	2007	10	2007_10_7	200	KU	0	-1339	4137	0	0	0	0	0
7	2007	11	2007_11_7	200	KU	0	0	0	0	1496	0	0	0
7	2007	12	2007_12_7	200	KU	0	0	0	0	0	0	0	0
7	2008	1	2008_1_7	200	KU	0	-809	0	0	0	0	0	0
7	2008	2	2008_2_7	200	KU	0	-837	0	0	0	0	0	0
7	2008	3	2008_3_7	200	KU	0	-823	0	0	0	0	0	0
7	2008	4	2008_4_7	200	KU	0	-1923	4036	0	0	0	0	0
8	2007	4	2007_4_8	210	KU	0	0	0	0	0	0	0	0
8	2007	5	2007_5_8	210	KU	0	0	0	0	0	0	0	0
8	2007	6	2007_6_8	210	KU	0	0	0	0	0	0	0	0
8	2007	7	2007_7_8	210	KU	0	0	0	0	0	0	0	0
8	2007	8	2007_8_8	210	KU	0	0	0	0	0	0	0	0
8	2007	9	2007_9_8	210	KU	0	0	0	0	0	0	0	0
8	2007	10	2007_10_8	210	KU	0	0	0	0	0	0	0	0
8	2007	11	2007_11_8	210	KU	0	0	0	0	0	0	0	0
8	2007	12	2007_12_8	210	KU	0	0	0	0	0	0	0	0
8	2008	1	2008_1_8	210	KU	0	0	0	0	0	0	0	0
8	2008	2	2008_2_8	210	KU	0	0	0	0	0	0	0	0
8	2008	3	2008_3_8	210	KU	0	0	0	0	0	0	0	0
8	2008	4	2008_4_8	210	KU	0	0	0	0	0	0	0	0
9	2007	4	2007_4_9	300	KU	0	0	82453	0	12264	0	0	0
9	2007	5	2007_5_9	300	KU	-104801	0	42865	0	0	0	0	0
9	2007	6	2007_6_9	300	KU	0	0	53486	0	0	0	0	0
9	2007	7	2007_7_9	300	KU	0	0	0	69182	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
9	2007	8	2007_8_9	300	KU	0	0	68841	0	0	0	0	0
9	2007	9	2007_9_9	300	KU	0	0	67060	0	0	0	0	0
9	2007	10	2007_10_9	300	KU	0	0	38625	0	33622	0	0	0
9	2007	11	2007_11_9	300	KU	0	0	0	0	0	-11760	0	0
9	2007	12	2007_12_9	300	KU	0	17396	0	0	0	0	0	0
9	2008	1	2008_1_9	300	KU	0	0	0	0	0	-15488	0	0
9	2008	2	2008_2_9	300	KU	0	0	0	0	0	-10716	0	0
9	2008	3	2008_3_9	300	KU	0	0	0	0	0	0	0	0
9	2008	4	2008_4_9	300	KU	0	0	80285	0	15073	0	0	0
10	2007	4	2007_4_10	305	KU	0	-14152	0	0	0	0	0	0
10	2007	5	2007_5_10	305	KU	0	0	0	0	0	0	0	0
10	2007	6	2007_6_10	305	KU	0	0	0	0	0	13336	0	0
10	2007	7	2007_7_10	305	KU	0	0	0	0	22845	0	0	0
10	2007	8	2007_8_10	305	KU	0	0	0	20775	0	0	0	0
10	2007	9	2007_9_10	305	KU	0	0	0	0	19247	0	0	0
10	2007	10	2007_10_10	305	KU	0	0	20625	0	13014	0	0	0
10	2007	11	2007_11_10	305	KU	0	0	0	0	0	0	0	0
10	2007	12	2007_12_10	305	KU	0	0	0	0	0	0	0	0
10	2008	1	2008_1_10	305	KU	0	0	0	0	0	0	0	0
10	2008	2	2008_2_10	305	KU	0	0	0	0	0	-7423	0	0
10	2008	3	2008_3_10	305	KU	0	0	0	0	0	-7605	0	0
10	2008	4	2008_4_10	305	KU	0	0	0	0	16718	0	0	0
11	2007	4	2007_4_11	320	KU	0	0	5090	0	0	0	0	0
11	2007	5	2007_5_11	320	KU	0	0	0	9375	0	0	0	0
11	2007	6	2007_6_11	320	KU	0	0	0	4219	0	0	0	0
11	2007	7	2007_7_11	320	KU	0	0	4894	0	0	0	0	0
11	2007	8	2007_8_11	320	KU	0	0	4738	0	0	0	0	0
11	2007	9	2007_9_11	320	KU	0	0	4397	0	0	0	0	0
11	2007	10	2007_10_11	320	KU	0	0	3950	0	0	0	0	0
11	2007	11	2007_11_11	320	KU	0	0	0	0	-649	0	0	0
11	2007	12	2007_12_11	320	KU	0	0	0	0	0	0	0	0
11	2008	1	2008_1_11	320	KU	712	0	0	0	0	0	0	0
11	2008	2	2008_2_11	320	KU	663	0	0	0	0	0	0	0
11	2008	3	2008_3_11	320	KU	626	0	0	0	0	0	0	0
11	2008	4	2008_4_11	320	KU	302	0	878	0	0	0	0	0
12	2007	4	2007_4_12	325	KU	0	0	0	0	12520	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
12	2007	5	2007_5_12	325	KU	0	0	0	0	0	0	0	0
12	2007	6	2007_6_12	325	KU	0	0	19220	0	0	0	0	0
12	2007	7	2007_7_12	325	KU	0	0	0	21730	0	0	0	0
12	2007	8	2007_8_12	325	KU	0	0	17922	0	0	0	0	0
12	2007	9	2007_9_12	325	KU	0	0	26267	0	0	0	0	0
12	2007	10	2007_10_12	325	KU	0	0	45764	0	0	0	0	0
12	2007	11	2007_11_12	325	KU	0	0	0	0	0	0	0	0
12	2007	12	2007_12_12	325	KU	0	0	0	0	0	0	0	0
12	2008	1	2008_1_12	325	KU	0	0	0	0	0	0	0	0
12	2008	2	2008_2_12	325	KU	0	0	0	0	0	0	0	0
12	2008	3	2008_3_12	325	KU	0	0	0	0	0	0	0	0
12	2008	4	2008_4_12	325	KU	0	0	0	0	11584	0	0	0
13	2007	4	2007_4_13	345	KU	0	0	0	0	0	0	0	0
13	2007	5	2007_5_13	345	KU	0	0	0	0	0	0	0	0
13	2007	6	2007_6_13	345	KU	0	0	0	0	0	0	0	0
13	2007	7	2007_7_13	345	KU	0	0	0	0	0	0	0	0
13	2007	8	2007_8_13	345	KU	0	0	0	0	0	0	0	0
13	2007	9	2007_9_13	345	KU	0	0	0	0	0	0	0	0
13	2007	10	2007_10_13	345	KU	0	0	0	0	0	0	0	0
13	2007	11	2007_11_13	345	KU	0	0	0	0	0	0	0	0
13	2007	12	2007_12_13	345	KU	0	0	0	0	0	0	0	0
13	2008	1	2008_1_13	345	KU	0	0	0	0	0	0	0	0
13	2008	2	2008_2_13	345	KU	0	0	0	0	0	0	0	0
13	2008	3	2008_3_13	345	KU	0	0	0	0	0	0	0	0
13	2008	4	2008_4_13	345	KU	0	0	0	0	0	0	0	0
14	2007	4	2007_4_14	420	KU	0	0	0	0	0	0	0	0
14	2007	5	2007_5_14	420	KU	0	0	0	0	0	0	0	0
14	2007	6	2007_6_14	420	KU	0	0	0	0	0	0	0	0
14	2007	7	2007_7_14	420	KU	0	0	0	0	0	0	0	0
14	2007	8	2007_8_14	420	KU	0	0	0	0	0	0	0	0
14	2007	9	2007_9_14	420	KU	0	0	0	0	0	0	0	0
14	2007	10	2007_10_14	420	KU	0	0	0	0	0	0	0	0
14	2007	11	2007_11_14	420	KU	0	0	0	0	0	0	0	0
14	2007	12	2007_12_14	420	KU	0	0	0	0	0	0	0	0
14	2008	1	2008_1_14	420	KU	0	0	0	0	0	0	0	0
14	2008	2	2008_2_14	420	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
14	2008	3	2008_3_14	420	KU	0	0	0	0	0	0	0	0
14	2008	4	2008_4_14	420	KU	0	0	0	0	0	0	0	0
15	2007	4	2007_4_15	440	KU	0	0	0	0	0	0	0	0
15	2007	5	2007_5_15	440	KU	0	0	0	0	0	0	0	0
15	2007	6	2007_6_15	440	KU	0	0	0	0	0	0	0	0
15	2007	7	2007_7_15	440	KU	0	0	0	0	0	0	0	0
15	2007	8	2007_8_15	440	KU	0	0	0	0	0	0	0	0
15	2007	9	2007_9_15	440	KU	0	0	0	0	0	0	0	0
15	2007	10	2007_10_15	440	KU	0	0	0	0	0	0	0	0
15	2007	11	2007_11_15	440	KU	0	0	0	0	0	0	0	0
15	2007	12	2007_12_15	440	KU	0	0	0	0	0	0	0	0
15	2008	1	2008_1_15	440	KU	0	0	0	0	0	0	0	0
15	2008	2	2008_2_15	440	KU	0	0	0	0	0	0	0	0
15	2008	3	2008_3_15	440	KU	0	0	0	0	0	0	0	0
15	2008	4	2008_4_15	440	KU	0	0	0	0	0	0	0	0
16	2007	4	2007_4_16	500	KU	0	0	0	0	0	0	0	0
16	2007	5	2007_5_16	500	KU	0	0	0	0	0	0	0	0
16	2007	6	2007_6_16	500	KU	0	0	0	0	0	0	0	0
16	2007	7	2007_7_16	500	KU	0	0	0	0	0	0	0	0
16	2007	8	2007_8_16	500	KU	0	0	0	0	0	0	0	0
16	2007	9	2007_9_16	500	KU	0	0	0	0	0	0	0	0
16	2007	10	2007_10_16	500	KU	0	0	0	0	0	0	0	0
16	2007	11	2007_11_16	500	KU	0	0	0	0	0	0	0	0
16	2007	12	2007_12_16	500	KU	0	0	0	0	0	0	0	0
16	2008	1	2008_1_16	500	KU	0	0	0	0	0	0	0	0
16	2008	2	2008_2_16	500	KU	0	0	0	0	0	0	0	0
16	2008	3	2008_3_16	500	KU	0	0	0	0	0	0	0	0
16	2008	4	2008_4_16	500	KU	0	0	0	0	0	0	0	0
17	2007	4	2007_4_17	505	KU	0	0	0	0	0	0	0	0
17	2007	5	2007_5_17	505	KU	0	0	0	0	0	0	0	0
17	2007	6	2007_6_17	505	KU	0	0	0	0	0	0	0	0
17	2007	7	2007_7_17	505	KU	0	0	0	0	0	0	0	0
17	2007	8	2007_8_17	505	KU	0	0	0	0	0	0	0	0
17	2007	9	2007_9_17	505	KU	0	0	0	0	0	0	0	0
17	2007	10	2007_10_17	505	KU	0	0	0	0	0	0	0	0
17	2007	11	2007_11_17	505	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
17	2007	12	2007_12_17	505	KU	0	0	0	0	0	0	0	0
17	2008	1	2008_1_17	505	KU	0	0	0	0	0	0	0	0
17	2008	2	2008_2_17	505	KU	0	0	0	0	0	0	0	0
17	2008	3	2008_3_17	505	KU	0	0	0	0	0	0	0	0
17	2008	4	2008_4_17	505	KU	0	0	0	0	0	0	0	0
18	2007	4	2007_4_18	510	KU	0	0	0	0	0	0	0	0
18	2007	5	2007_5_18	510	KU	0	0	0	0	0	0	0	0
18	2007	6	2007_6_18	510	KU	0	0	0	0	0	0	0	0
18	2007	7	2007_7_18	510	KU	0	0	0	0	0	0	0	0
18	2007	8	2007_8_18	510	KU	0	0	0	0	0	0	0	0
18	2007	9	2007_9_18	510	KU	0	0	0	0	0	0	0	0
18	2007	10	2007_10_18	510	KU	0	0	0	0	0	0	0	0
18	2007	11	2007_11_18	510	KU	0	0	0	0	0	0	0	0
18	2007	12	2007_12_18	510	KU	0	0	0	0	0	0	0	0
18	2008	1	2008_1_18	510	KU	0	0	0	0	0	0	0	0
18	2008	2	2008_2_18	510	KU	0	0	0	0	0	0	0	0
18	2008	3	2008_3_18	510	KU	0	0	0	0	0	0	0	0
18	2008	4	2008_4_18	510	KU	0	0	0	0	0	0	0	0
19	2007	4	2007_4_19	515	KU	0	0	0	0	0	0	0	0
19	2007	5	2007_5_19	515	KU	0	0	0	0	0	0	0	0
19	2007	6	2007_6_19	515	KU	0	0	0	0	0	0	0	0
19	2007	7	2007_7_19	515	KU	0	0	0	0	0	0	0	0
19	2007	8	2007_8_19	515	KU	0	0	0	0	0	0	0	0
19	2007	9	2007_9_19	515	KU	0	0	0	0	0	0	0	0
19	2007	10	2007_10_19	515	KU	0	0	0	0	0	0	0	0
19	2007	11	2007_11_19	515	KU	0	0	0	0	0	0	0	0
19	2007	12	2007_12_19	515	KU	0	0	0	0	0	0	0	0
19	2008	1	2008_1_19	515	KU	0	0	0	0	0	0	0	0
19	2008	2	2008_2_19	515	KU	0	0	0	0	0	0	0	0
19	2008	3	2008_3_19	515	KU	0	0	0	0	0	0	0	0
19	2008	4	2008_4_19	515	KU	0	0	0	0	0	0	0	0
20	2007	4	2007_4_20	520	KU	0	0	0	0	0	0	0	0
20	2007	5	2007_5_20	520	KU	0	0	0	0	0	0	0	0
20	2007	6	2007_6_20	520	KU	0	0	0	0	0	0	0	0
20	2007	7	2007_7_20	520	KU	0	0	0	0	0	0	0	0
20	2007	8	2007_8_20	520	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
20	2007	9	2007_9_20	520	KU	0	0	0	0	0	0	0	0
20	2007	10	2007_10_20	520	KU	0	0	0	0	0	0	0	0
20	2007	11	2007_11_20	520	KU	0	0	0	0	0	0	0	0
20	2007	12	2007_12_20	520	KU	0	0	0	0	0	0	0	0
20	2008	1	2008_1_20	520	KU	0	0	0	0	0	0	0	0
20	2008	2	2008_2_20	520	KU	0	0	0	0	0	0	0	0
20	2008	3	2008_3_20	520	KU	0	0	0	0	0	0	0	0
20	2008	4	2008_4_20	520	KU	0	0	0	0	0	0	0	0
21	2007	4	2007_4_21	530	KU	0	0	0	0	0	0	0	0
21	2007	5	2007_5_21	530	KU	0	0	0	0	0	0	0	0
21	2007	6	2007_6_21	530	KU	0	0	0	0	0	0	0	0
21	2007	7	2007_7_21	530	KU	0	0	0	0	0	0	0	0
21	2007	8	2007_8_21	530	KU	0	0	0	0	0	0	0	0
21	2007	9	2007_9_21	530	KU	0	0	0	0	0	0	0	0
21	2007	10	2007_10_21	530	KU	0	0	0	0	0	0	0	0
21	2007	11	2007_11_21	530	KU	0	0	0	0	0	0	0	0
21	2007	12	2007_12_21	530	KU	0	0	0	0	0	0	0	0
21	2008	1	2008_1_21	530	KU	0	0	0	0	0	0	0	0
21	2008	2	2008_2_21	530	KU	0	0	0	0	0	0	0	0
21	2008	3	2008_3_21	530	KU	0	0	0	0	0	0	0	0
21	2008	4	2008_4_21	530	KU	0	0	0	0	0	0	0	0
22	2007	4	2007_4_22	615	KU	0	0	0	0	0	0	0	0
22	2007	5	2007_5_22	615	KU	0	0	0	0	0	0	0	0
22	2007	6	2007_6_22	615	KU	0	0	0	0	0	0	0	0
22	2007	7	2007_7_22	615	KU	0	0	0	0	0	0	0	0
22	2007	8	2007_8_22	615	KU	0	0	0	0	0	0	0	0
22	2007	9	2007_9_22	615	KU	0	0	0	0	0	0	0	0
22	2007	10	2007_10_22	615	KU	0	0	0	0	0	0	0	0
22	2007	11	2007_11_22	615	KU	0	0	0	0	0	0	0	0
22	2007	12	2007_12_22	615	KU	0	0	0	0	0	0	0	0
22	2008	1	2008_1_22	615	KU	0	0	0	0	0	0	0	0
22	2008	2	2008_2_22	615	KU	0	0	0	0	0	0	0	0
22	2008	3	2008_3_22	615	KU	0	0	0	0	0	0	0	0
22	2008	4	2008_4_22	615	KU	0	0	0	0	0	0	0	0
23	2007	4	2007_4_23	700	KU	0	0	36797	0	0	0	0	0
23	2007	5	2007_5_23	700	KU	0	0	0	0	0	15600	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
23	2007	6	2007_6_23	700	KU	0	0	0	0	0	14820	0	0
23	2007	7	2007_7_23	700	KU	0	0	21975	0	0	0	0	0
23	2007	8	2007_8_23	700	KU	0	0	24801	0	0	0	0	0
23	2007	9	2007_9_23	700	KU	0	-20569	27329	0	0	0	0	0
23	2007	10	2007_10_23	700	KU	0	0	35673	0	0	0	0	0
23	2007	11	2007_11_23	700	KU	6068	0	0	0	0	0	0	0
23	2007	12	2007_12_23	700	KU	0	0	0	0	0	-5924	0	0
23	2008	1	2008_1_23	700	KU	10644	0	0	0	0	0	0	0
23	2008	2	2008_2_23	700	KU	9622	0	0	0	0	0	0	0
23	2008	3	2008_3_23	700	KU	0	0	0	0	0	-8403	0	0
23	2008	4	2008_4_23	700	KU	4481	0	0	0	0	0	0	0
24	2007	4	2007_4_24	710	KU	0	17064	80686	0	0	0	0	0
24	2007	5	2007_5_24	710	KU	0	0	33358	0	0	22401	0	0
24	2007	6	2007_6_24	710	KU	0	0	35165	0	0	24400	0	0
24	2007	7	2007_7_24	710	KU	0	0	66363	0	0	0	0	0
24	2007	8	2007_8_24	710	KU	0	0	0	67696	0	0	0	0
24	2007	9	2007_9_24	710	KU	0	0	70134	0	0	0	0	0
24	2007	10	2007_10_24	710	KU	0	0	69611	0	0	0	0	0
24	2007	11	2007_11_24	710	KU	21658	0	0	0	0	0	0	0
24	2007	12	2007_12_24	710	KU	26624	0	0	0	0	0	0	0
24	2008	1	2008_1_24	710	KU	35601	0	0	0	0	0	0	0
24	2008	2	2008_2_24	710	KU	35964	0	0	0	0	0	0	0
24	2008	3	2008_3_24	710	KU	31918	0	0	0	0	0	0	0
24	2008	4	2008_4_24	710	KU	16386	0	38676	0	0	0	0	0
25	2007	4	2007_4_25	720	KU	0	0	0	0	0	0	0	0
25	2007	5	2007_5_25	720	KU	0	0	0	0	0	0	0	0
25	2007	6	2007_6_25	720	KU	0	0	0	0	0	0	0	0
25	2007	7	2007_7_25	720	KU	0	0	0	0	0	0	0	0
25	2007	8	2007_8_25	720	KU	0	0	0	0	0	0	0	0
25	2007	9	2007_9_25	720	KU	0	0	0	0	0	0	0	0
25	2007	10	2007_10_25	720	KU	0	0	0	0	0	0	0	0
25	2007	11	2007_11_25	720	KU	0	0	0	0	0	0	0	0
25	2007	12	2007_12_25	720	KU	0	0	0	0	0	0	0	0
25	2008	1	2008_1_25	720	KU	0	0	0	0	0	0	0	0
25	2008	2	2008_2_25	720	KU	0	0	0	0	0	0	0	0
25	2008	3	2008_3_25	720	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
25	2008	4	2008_4_25	720	KU	0	0	0	0	0	0	0	0
26	2007	4	2007_4_26	730	KU	42952	0	0	0	0	0	0	0
26	2007	5	2007_5_26	730	KU	0	0	0	0	0	0	0	0
26	2007	6	2007_6_26	730	KU	0	0	0	21560	0	0	0	0
26	2007	7	2007_7_26	730	KU	0	0	0	31291	0	0	0	0
26	2007	8	2007_8_26	730	KU	0	0	0	0	31806	0	0	0
26	2007	9	2007_9_26	730	KU	0	0	0	16903	8540	0	0	0
26	2007	10	2007_10_26	730	KU	0	0	28506	0	-18334	0	0	0
26	2007	11	2007_11_26	730	KU	0	32017	0	0	0	0	0	0
26	2007	12	2007_12_26	730	KU	0	0	0	0	-35798	0	0	0
26	2008	1	2008_1_26	730	KU	55608	0	0	0	0	0	0	0
26	2008	2	2008_2_26	730	KU	40340	0	0	0	0	0	0	0
26	2008	3	2008_3_26	730	KU	39650	0	0	0	0	0	0	0
26	2008	4	2008_4_26	730	KU	0	28984	0	0	0	0	0	0
27	2007	4	2007_4_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	5	2007_5_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	6	2007_6_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	7	2007_7_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	8	2007_8_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	9	2007_9_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	10	2007_10_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	11	2007_11_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2007	12	2007_12_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2008	1	2008_1_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2008	2	2008_2_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2008	3	2008_3_27	Street Ligh	KU	0	0	0	0	0	0	0	0
27	2008	4	2008_4_27	Street Ligh	KU	0	0	0	0	0	0	0	0
28	2007	4	2007_4_28	800	KU	0	0	0	0	0	0	0	0
28	2007	5	2007_5_28	800	KU	0	0	0	0	0	0	0	0
28	2007	6	2007_6_28	800	KU	0	0	0	0	0	0	0	0
28	2007	7	2007_7_28	800	KU	0	0	0	0	0	0	0	0
28	2007	8	2007_8_28	800	KU	0	0	0	0	0	0	0	0
28	2007	9	2007_9_28	800	KU	0	0	0	0	0	0	0	0
28	2007	10	2007_10_28	800	KU	0	0	0	0	0	0	0	0
28	2007	11	2007_11_28	800	KU	0	0	0	0	0	0	0	0
28	2007	12	2007_12_28	800	KU	0	0	0	0	0	0	0	0

KU Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
28	2008	1	2008_1_28	800	KU	0	0	0	0	0	0	0	0
28	2008	2	2008_2_28	800	KU	0	0	0	0	0	0	0	0
28	2008	3	2008_3_28	800	KU	0	0	0	0	0	0	0	0
28	2008	4	2008_4_28	800	KU	0	0	0	0	0	0	0	0
29	2007	4	2007_4_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	5	2007_5_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	6	2007_6_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	7	2007_7_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	8	2007_8_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	9	2007_9_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	10	2007_10_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	11	2007_11_29	Open	KU	0	0	0	0	0	0	0	0
29	2007	12	2007_12_29	Open	KU	0	0	0	0	0	0	0	0
29	2008	1	2008_1_29	Open	KU	0	0	0	0	0	0	0	0
29	2008	2	2008_2_29	Open	KU	0	0	0	0	0	0	0	0
29	2008	3	2008_3_29	Open	KU	0	0	0	0	0	0	0	0
29	2008	4	2008_4_29	Open	KU	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
1	2007	4	2007_4_1	1	LGE	107192	0	372064	0	0	0	0	0
1	2007	5	2007_5_1	1	LGE	0	0	0	364156	0	167482	0	0
1	2007	6	2007_6_1	1	LGE	0	0	298343	0	0	176666	0	0
1	2007	7	2007_7_1	1	LGE	0	0	227194	0	0	246777	0	0
1	2007	8	2007_8_1	1	LGE	0	0	0	512577	145063	0	0	0
1	2007	9	2007_9_1	1	LGE	0	0	0	528845	0	0	0	0
1	2007	10	2007_10_1	1	LGE	0	0	0	716870	0	0	0	0
1	2007	11	2007_11_1	1	LGE	194147	0	0	0	0	0	0	0
1	2007	12	2007_12_1	1	LGE	125135	0	0	0	0	0	0	0
1	2008	1	2008_1_1	1	LGE	0	154487	0	0	0	0	0	0
1	2008	2	2008_2_1	1	LGE	0	156404	0	0	0	0	0	0
1	2008	3	2008_3_1	1	LGE	0	140237	0	0	0	0	0	0
1	2008	4	2008_4_1	1	LGE	94764	0	220853	0	0	0	0	0
2	2007	4	2007_4_2	100	LGE	0	0	0	67918	0	0	0	0
2	2007	5	2007_5_2	100	LGE	0	0	30151	0	0	0	0	0
2	2007	6	2007_6_2	100	LGE	0	0	28349	0	0	0	0	0
2	2007	7	2007_7_2	100	LGE	0	0	0	0	0	12049	0	0
2	2007	8	2007_8_2	100	LGE	0	0	0	18679	0	0	0	0
2	2007	9	2007_9_2	100	LGE	0	0	27803	0	0	0	0	0
2	2007	10	2007_10_2	100	LGE	0	0	28656	0	0	0	0	0
2	2007	11	2007_11_2	100	LGE	0	0	0	0	0	-3654	0	0
2	2007	12	2007_12_2	100	LGE	0	0	0	0	0	-6381	0	0
2	2008	1	2008_1_2	100	LGE	0	5580	0	0	0	0	0	0
2	2008	2	2008_2_2	100	LGE	0	0	0	0	0	-4445	0	0
2	2008	3	2008_3_2	100	LGE	0	0	0	0	0	-3950	0	0
2	2008	4	2008_4_2	100	LGE	0	0	0	0	0	0	0	0
3	2007	4	2007_4_3	105	LGE	10065	0	67455	0	0	0	0	0
3	2007	5	2007_5_3	105	LGE	0	0	0	0	0	30852	0	0
3	2007	6	2007_6_3	105	LGE	0	0	0	39034	0	0	0	0
3	2007	7	2007_7_3	105	LGE	0	0	40027	0	0	0	0	0
3	2007	8	2007_8_3	105	LGE	0	0	48835	0	0	0	0	0
3	2007	9	2007_9_3	105	LGE	0	0	45218	0	0	0	0	0
3	2007	10	2007_10_3	105	LGE	0	15743	58301	0	0	0	0	0
3	2007	11	2007_11_3	105	LGE	9478	0	0	0	0	0	0	0
3	2007	12	2007_12_3	105	LGE	8433	0	0	0	0	0	0	0
3	2008	1	2008_1_3	105	LGE	8456	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
3	2008	2	2008_2_3	105	LGE	0	0	0	0	0	-11799	0	0
3	2008	3	2008_3_3	105	LGE	0	8360	0	0	0	0	0	0
3	2008	4	2008_4_3	105	LGE	0	0	0	0	0	0	0	0
4	2007	4	2007_4_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	5	2007_5_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	6	2007_6_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	7	2007_7_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	8	2007_8_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	9	2007_9_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	10	2007_10_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	11	2007_11_4	120	LGE	0	0	0	0	0	0	0	0
4	2007	12	2007_12_4	120	LGE	0	0	0	0	0	0	0	0
4	2008	1	2008_1_4	120	LGE	0	0	0	0	0	0	0	0
4	2008	2	2008_2_4	120	LGE	0	0	0	0	0	0	0	0
4	2008	3	2008_3_4	120	LGE	0	0	0	0	0	0	0	0
4	2008	4	2008_4_4	120	LGE	0	0	0	0	0	0	0	0
5	2007	4	2007_4_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	5	2007_5_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	6	2007_6_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	7	2007_7_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	8	2007_8_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	9	2007_9_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	10	2007_10_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	11	2007_11_5	125	LGE	0	0	0	0	0	0	0	0
5	2007	12	2007_12_5	125	LGE	0	0	0	0	0	0	0	0
5	2008	1	2008_1_5	125	LGE	0	0	0	0	0	0	0	0
5	2008	2	2008_2_5	125	LGE	0	0	0	0	0	0	0	0
5	2008	3	2008_3_5	125	LGE	0	0	0	0	0	0	0	0
5	2008	4	2008_4_5	125	LGE	0	0	0	0	0	0	0	0
6	2007	4	2007_4_6	200	LGE	0	-574	3306	0	0	0	0	0
6	2007	5	2007_5_6	200	LGE	0	-6560	3069	0	0	0	0	0
6	2007	6	2007_6_6	200	LGE	0	0	0	2948	0	0	0	0
6	2007	7	2007_7_6	200	LGE	0	0	3932	0	0	0	0	0
6	2007	8	2007_8_6	200	LGE	0	0	1927	0	2032	0	0	0
6	2007	9	2007_9_6	200	LGE	0	0	1656	0	1535	0	0	0
6	2007	10	2007_10_6	200	LGE	0	-986	0	4395	601	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
6	2007	11	2007_11_6	200	LGE	1040	0	0	0	1478	0	0	0
6	2007	12	2007_12_6	200	LGE	0	0	0	0	579	0	0	0
6	2008	1	2008_1_6	200	LGE	0	0	0	0	327	0	0	0
6	2008	2	2008_2_6	200	LGE	0	0	0	0	448	0	0	0
6	2008	3	2008_3_6	200	LGE	0	0	0	0	298	0	0	0
6	2008	4	2008_4_6	200	LGE	0	0	0	0	602	364	0	0
7	2007	4	2007_4_7	210	LGE	0	0	578	0	0	0	0	0
7	2007	5	2007_5_7	210	LGE	0	0	505	0	0	0	0	0
7	2007	6	2007_6_7	210	LGE	0	0	464	0	0	0	0	0
7	2007	7	2007_7_7	210	LGE	0	0	333	0	0	0	0	0
7	2007	8	2007_8_7	210	LGE	0	0	429	0	0	0	0	0
7	2007	9	2007_9_7	210	LGE	0	0	0	0	237	175	0	0
7	2007	10	2007_10_7	210	LGE	0	-115	378	0	0	0	0	0
7	2007	11	2007_11_7	210	LGE	0	0	1897	0	0	0	0	0
7	2007	12	2007_12_7	210	LGE	0	0	0	0	0	0	0	0
7	2008	1	2008_1_7	210	LGE	0	0	0	0	51	0	0	0
7	2008	2	2008_2_7	210	LGE	80	0	0	0	0	0	0	0
7	2008	3	2008_3_7	210	LGE	0	0	0	0	79	0	0	0
7	2008	4	2008_4_7	210	LGE	0	0	503	0	97	0	0	0
8	2007	4	2007_4_8	220	LGE	0	0	95794	0	0	0	0	0
8	2007	5	2007_5_8	220	LGE	-135894	0	69996	0	0	0	0	0
8	2007	6	2007_6_8	220	LGE	0	0	70663	0	0	0	0	0
8	2007	7	2007_7_8	220	LGE	0	0	68912	0	0	0	0	0
8	2007	8	2007_8_8	220	LGE	0	0	0	108623	0	-27950	0	0
8	2007	9	2007_9_8	220	LGE	0	0	44108	0	23766	0	0	0
8	2007	10	2007_10_8	220	LGE	0	0	61622	0	18795	0	0	0
8	2007	11	2007_11_8	220	LGE	0	0	0	0	0	-9415	0	0
8	2007	12	2007_12_8	220	LGE	0	0	0	0	0	0	0	0
8	2008	1	2008_1_8	220	LGE	19025	0	0	0	0	0	0	0
8	2008	2	2008_2_8	220	LGE	16168	0	0	0	0	0	0	0
8	2008	3	2008_3_8	220	LGE	12875	0	0	0	0	0	0	0
8	2008	4	2008_4_8	220	LGE	0	0	63508	0	0	0	0	0
9	2007	4	2007_4_9	230	LGE	0	0	5970	0	0	0	0	0
9	2007	5	2007_5_9	230	LGE	0	0	6422	0	0	0	0	0
9	2007	6	2007_6_9	230	LGE	0	0	4234	0	0	0	0	0
9	2007	7	2007_7_9	230	LGE	0	0	3492	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
9	2007	8	2007_8_9	230	LGE	0	0	3754	0	3488	0	0	0
9	2007	9	2007_9_9	230	LGE	0	0	2737	0	2781	0	0	0
9	2007	10	2007_10_9	230	LGE	0	-3096	6004	0	0	0	0	0
9	2007	11	2007_11_9	230	LGE	0	0	0	0	0	0	0	0
9	2007	12	2007_12_9	230	LGE	0	0	0	0	0	0	0	0
9	2008	1	2008_1_9	230	LGE	0	0	0	0	0	-626	0	0
9	2008	2	2008_2_9	230	LGE	683	0	0	0	0	0	0	0
9	2008	3	2008_3_9	230	LGE	0	0	0	0	-653	0	0	0
9	2008	4	2008_4_9	230	LGE	0	0	2703	0	1399	0	0	0
10	2007	4	2007_4_10	240	LGE	0	0	12557	0	0	0	0	0
10	2007	5	2007_5_10	240	LGE	0	0	9330	0	0	0	0	0
10	2007	6	2007_6_10	240	LGE	0	0	0	0	0	5496	0	0
10	2007	7	2007_7_10	240	LGE	0	0	0	10085	0	0	0	0
10	2007	8	2007_8_10	240	LGE	0	0	4721	0	5597	0	0	0
10	2007	9	2007_9_10	240	LGE	0	0	4421	0	0	0	0	0
10	2007	10	2007_10_10	240	LGE	0	-3393	7286	0	0	0	0	0
10	2007	11	2007_11_10	240	LGE	0	0	0	0	0	-1031	0	0
10	2007	12	2007_12_10	240	LGE	0	0	0	0	0	-1451	0	0
10	2008	1	2008_1_10	240	LGE	0	0	0	0	0	-3119	0	0
10	2008	2	2008_2_10	240	LGE	2929	0	0	0	0	0	0	0
10	2008	3	2008_3_10	240	LGE	2541	0	0	0	0	0	0	0
10	2008	4	2008_4_10	240	LGE	0	0	4304	0	0	1087	0	0
11	2007	4	2007_4_11	250	LGE	0	0	0	0	2545	1402	0	0
11	2007	5	2007_5_11	250	LGE	0	0	6671	0	0	0	0	0
11	2007	6	2007_6_11	250	LGE	0	0	3910	0	0	0	0	0
11	2007	7	2007_7_11	250	LGE	0	0	0	0	0	0	0	0
11	2007	8	2007_8_11	250	LGE	0	0	0	0	0	0	0	0
11	2007	9	2007_9_11	250	LGE	0	0	0	0	6023	0	0	0
11	2007	10	2007_10_11	250	LGE	0	0	4860	0	0	0	0	0
11	2007	11	2007_11_11	250	LGE	-2327	0	0	0	0	0	0	0
11	2007	12	2007_12_11	250	LGE	0	0	0	0	0	0	0	0
11	2008	1	2008_1_11	250	LGE	0	0	0	0	0	0	0	0
11	2008	2	2008_2_11	250	LGE	0	0	0	0	0	0	0	0
11	2008	3	2008_3_11	250	LGE	0	0	0	0	0	0	0	0
11	2008	4	2008_4_11	250	LGE	0	0	0	0	3643	1442	0	0
12	2007	4	2007_4_12	260	LGE	0	0	0	0	1478	814	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
12	2007	5	2007_5_12	260	LGE	0	0	4065	0	0	0	0	0
12	2007	6	2007_6_12	260	LGE	0	0	2535	0	0	0	0	0
12	2007	7	2007_7_12	260	LGE	0	0	6624	0	0	0	0	0
12	2007	8	2007_8_12	260	LGE	0	0	4098	0	0	0	0	0
12	2007	9	2007_9_12	260	LGE	0	0	0	0	3912	0	0	0
12	2007	10	2007_10_12	260	LGE	0	0	2840	0	0	0	0	0
12	2007	11	2007_11_12	260	LGE	0	-1124	0	0	0	0	0	0
12	2007	12	2007_12_12	260	LGE	0	0	0	0	0	0	0	0
12	2008	1	2008_1_12	260	LGE	0	0	0	0	0	0	0	0
12	2008	2	2008_2_12	260	LGE	0	0	0	0	0	0	0	0
12	2008	3	2008_3_12	260	LGE	0	0	0	0	0	0	0	0
12	2008	4	2008_4_12	260	LGE	0	0	0	0	2169	864	0	0
13	2007	4	2007_4_13	300	LGE	0	-5650	0	0	0	0	0	0
13	2007	5	2007_5_13	300	LGE	0	0	0	0	0	0	0	0
13	2007	6	2007_6_13	300	LGE	0	0	0	9790	0	0	0	0
13	2007	7	2007_7_13	300	LGE	0	0	0	0	0	0	0	0
13	2007	8	2007_8_13	300	LGE	0	0	0	0	9782	0	0	0
13	2007	9	2007_9_13	300	LGE	0	53742	0	0	9072	0	0	0
13	2007	10	2007_10_13	300	LGE	0	0	8315	0	3949	0	0	0
13	2007	11	2007_11_13	300	LGE	0	0	0	0	0	0	0	0
13	2007	12	2007_12_13	300	LGE	0	0	0	0	0	0	0	0
13	2008	1	2008_1_13	300	LGE	0	0	0	0	0	0	0	0
13	2008	2	2008_2_13	300	LGE	0	0	0	0	0	0	0	0
13	2008	3	2008_3_13	300	LGE	0	0	0	0	0	0	0	0
13	2008	4	2008_4_13	300	LGE	0	0	0	0	4272	1612	0	0
14	2007	4	2007_4_14	320	LGE	0	0	0	0	869	0	0	0
14	2007	5	2007_5_14	320	LGE	0	-3784	0	0	0	0	0	0
14	2007	6	2007_6_14	320	LGE	0	0	0	0	0	0	0	0
14	2007	7	2007_7_14	320	LGE	0	0	0	0	0	0	0	0
14	2007	8	2007_8_14	320	LGE	0	0	0	0	1598	0	0	0
14	2007	9	2007_9_14	320	LGE	0	0	0	0	1528	0	0	0
14	2007	10	2007_10_14	320	LGE	0	0	1997	0	0	0	0	0
14	2007	11	2007_11_14	320	LGE	0	0	0	0	0	0	0	0
14	2007	12	2007_12_14	320	LGE	0	0	0	0	0	0	0	0
14	2008	1	2008_1_14	320	LGE	0	0	0	0	0	0	0	0
14	2008	2	2008_2_14	320	LGE	954	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
14	2008	3	2008_3_14	320	LGE	0	0	0	0	0	0	0	0
14	2008	4	2008_4_14	320	LGE	0	0	0	0	1053	0	0	0
15	2007	4	2007_4_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	5	2007_5_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	6	2007_6_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	7	2007_7_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	8	2007_8_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	9	2007_9_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	10	2007_10_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	11	2007_11_15	400	LGE	0	0	0	0	0	0	0	0
15	2007	12	2007_12_15	400	LGE	0	0	0	0	0	0	0	0
15	2008	1	2008_1_15	400	LGE	0	0	0	0	0	0	0	0
15	2008	2	2008_2_15	400	LGE	0	0	0	0	0	0	0	0
15	2008	3	2008_3_15	400	LGE	0	0	0	0	0	0	0	0
15	2008	4	2008_4_15	400	LGE	0	0	0	0	0	0	0	0
16	2007	4	2007_4_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	5	2007_5_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	6	2007_6_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	7	2007_7_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	8	2007_8_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	9	2007_9_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	10	2007_10_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	11	2007_11_16	420	LGE	0	0	0	0	0	0	0	0
16	2007	12	2007_12_16	420	LGE	0	0	0	0	0	0	0	0
16	2008	1	2008_1_16	420	LGE	0	0	0	0	0	0	0	0
16	2008	2	2008_2_16	420	LGE	0	0	0	0	0	0	0	0
16	2008	3	2008_3_16	420	LGE	0	0	0	0	0	0	0	0
16	2008	4	2008_4_16	420	LGE	0	0	0	0	0	0	0	0
17	2007	4	2007_4_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	5	2007_5_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	6	2007_6_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	7	2007_7_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	8	2007_8_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	9	2007_9_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	10	2007_10_17	430	LGE	0	0	0	0	0	0	0	0
17	2007	11	2007_11_17	430	LGE	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
17	2007	12	2007_12_17	430	LGE	0	0	0	0	0	0	0	0
17	2008	1	2008_1_17	430	LGE	0	0	0	0	0	0	0	0
17	2008	2	2008_2_17	430	LGE	0	0	0	0	0	0	0	0
17	2008	3	2008_3_17	430	LGE	0	0	0	0	0	0	0	0
17	2008	4	2008_4_17	430	LGE	0	0	0	0	0	0	0	0
18	2007	4	2007_4_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	5	2007_5_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	6	2007_6_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	7	2007_7_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	8	2007_8_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	9	2007_9_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	10	2007_10_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	11	2007_11_18	440	LGE	0	0	0	0	0	0	0	0
18	2007	12	2007_12_18	440	LGE	0	0	0	0	0	0	0	0
18	2008	1	2008_1_18	440	LGE	0	0	0	0	0	0	0	0
18	2008	2	2008_2_18	440	LGE	0	0	0	0	0	0	0	0
18	2008	3	2008_3_18	440	LGE	0	0	0	0	0	0	0	0
18	2008	4	2008_4_18	440	LGE	0	0	0	0	0	0	0	0
19	2007	4	2007_4_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	5	2007_5_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	6	2007_6_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	7	2007_7_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	8	2007_8_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	9	2007_9_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	10	2007_10_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	11	2007_11_19	450	LGE	0	0	0	0	0	0	0	0
19	2007	12	2007_12_19	450	LGE	0	0	0	0	0	0	0	0
19	2008	1	2008_1_19	450	LGE	0	0	0	0	0	0	0	0
19	2008	2	2008_2_19	450	LGE	0	0	0	0	0	0	0	0
19	2008	3	2008_3_19	450	LGE	0	0	0	0	0	0	0	0
19	2008	4	2008_4_19	450	LGE	0	0	0	0	0	0	0	0
20	2007	4	2007_4_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	5	2007_5_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	6	2007_6_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	7	2007_7_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	8	2007_8_20	600	LGE	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
20	2007	9	2007_9_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	10	2007_10_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	11	2007_11_20	600	LGE	0	0	0	0	0	0	0	0
20	2007	12	2007_12_20	600	LGE	0	0	0	0	0	0	0	0
20	2008	1	2008_1_20	600	LGE	0	0	0	0	0	0	0	0
20	2008	2	2008_2_20	600	LGE	0	0	0	0	0	0	0	0
20	2008	3	2008_3_20	600	LGE	0	0	0	0	0	0	0	0
20	2008	4	2008_4_20	600	LGE	0	0	0	0	0	0	0	0
21	2007	4	2007_4_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	5	2007_5_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	6	2007_6_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	7	2007_7_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	8	2007_8_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	9	2007_9_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	10	2007_10_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	11	2007_11_21	800	LGE	0	0	0	0	0	0	0	0
21	2007	12	2007_12_21	800	LGE	0	0	0	0	0	0	0	0
21	2008	1	2008_1_21	800	LGE	0	0	0	0	0	0	0	0
21	2008	2	2008_2_21	800	LGE	0	0	0	0	0	0	0	0
21	2008	3	2008_3_21	800	LGE	0	0	0	0	0	0	0	0
21	2008	4	2008_4_21	800	LGE	0	0	0	0	0	0	0	0
22	2007	4	2007_4_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	5	2007_5_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	6	2007_6_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	7	2007_7_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	8	2007_8_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	9	2007_9_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	10	2007_10_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	11	2007_11_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2007	12	2007_12_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2008	1	2008_1_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2008	2	2008_2_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2008	3	2008_3_22	Other OL	LGE	0	0	0	0	0	0	0	0
22	2008	4	2008_4_22	Other OL	LGE	0	0	0	0	0	0	0	0
23	2007	4	2007_4_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	5	2007_5_23	RS OL	LGE	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
23	2007	6	2007_6_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	7	2007_7_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	8	2007_8_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	9	2007_9_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	10	2007_10_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	11	2007_11_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2007	12	2007_12_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2008	1	2008_1_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2008	2	2008_2_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2008	3	2008_3_23	RS OL	LGE	0	0	0	0	0	0	0	0
23	2008	4	2008_4_23	RS OL	LGE	0	0	0	0	0	0	0	0
24	2007	4	2007_4_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	5	2007_5_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	6	2007_6_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	7	2007_7_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	8	2007_8_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	9	2007_9_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	10	2007_10_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	11	2007_11_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2007	12	2007_12_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2008	1	2008_1_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2008	2	2008_2_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2008	3	2008_3_24	Comm OL	LGE	0	0	0	0	0	0	0	0
24	2008	4	2008_4_24	Comm OL	LGE	0	0	0	0	0	0	0	0
25	2007	4	2007_4_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	5	2007_5_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	6	2007_6_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	7	2007_7_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	8	2007_8_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	9	2007_9_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	10	2007_10_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	11	2007_11_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2007	12	2007_12_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2008	1	2008_1_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2008	2	2008_2_25	PSL	LGE	0	0	0	0	0	0	0	0
25	2008	3	2008_3_25	PSL	LGE	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
25	2008	4	2008_4_25	PSL	LGE	0	0	0	0	0	0	0	0
26	2007	4	2007_4_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	5	2007_5_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	6	2007_6_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	7	2007_7_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	8	2007_8_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	9	2007_9_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	10	2007_10_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	11	2007_11_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2007	12	2007_12_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2008	1	2008_1_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2008	2	2008_2_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2008	3	2008_3_26	SLE	LGE	0	0	0	0	0	0	0	0
26	2008	4	2008_4_26	SLE	LGE	0	0	0	0	0	0	0	0
27	2007	4	2007_4_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	5	2007_5_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	6	2007_6_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	7	2007_7_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	8	2007_8_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	9	2007_9_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	10	2007_10_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	11	2007_11_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2007	12	2007_12_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2008	1	2008_1_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2008	2	2008_2_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2008	3	2008_3_27	TLE	LGE	0	0	0	0	0	0	0	0
27	2008	4	2008_4_27	TLE	LGE	0	0	0	0	0	0	0	0
28	2007	4	2007_4_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	5	2007_5_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	6	2007_6_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	7	2007_7_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	8	2007_8_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	9	2007_9_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	10	2007_10_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	11	2007_11_28	Open	LGE	0	0	0	0	0	0	0	0
28	2007	12	2007_12_28	Open	LGE	0	0	0	0	0	0	0	0

LE Coefficients

Index	Year	Month	Lookup	Class	Company	HDD60	HDD65	CDD65	CDD70	MinTemp	MaxTemp	Open	Open
28	2008	1	2008_1_28	Open	LGE	0	0	0	0	0	0	0	0
28	2008	2	2008_2_28	Open	LGE	0	0	0	0	0	0	0	0
28	2008	3	2008_3_28	Open	LGE	0	0	0	0	0	0	0	0
28	2008	4	2008_4_28	Open	LGE	0	0	0	0	0	0	0	0
29	2007	4	2007_4_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	5	2007_5_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	6	2007_6_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	7	2007_7_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	8	2007_8_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	9	2007_9_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	10	2007_10_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	11	2007_11_29	Open	LGE	0	0	0	0	0	0	0	0
29	2007	12	2007_12_29	Open	LGE	0	0	0	0	0	0	0	0
29	2008	1	2008_1_29	Open	LGE	0	0	0	0	0	0	0	0
29	2008	2	2008_2_29	Open	LGE	0	0	0	0	0	0	0	0
29	2008	3	2008_3_29	Open	LGE	0	0	0	0	0	0	0	0
29	2008	4	2008_4_29	Open	LGE	0	0	0	0	0	0	0	0

KU & LG&E Coefficients

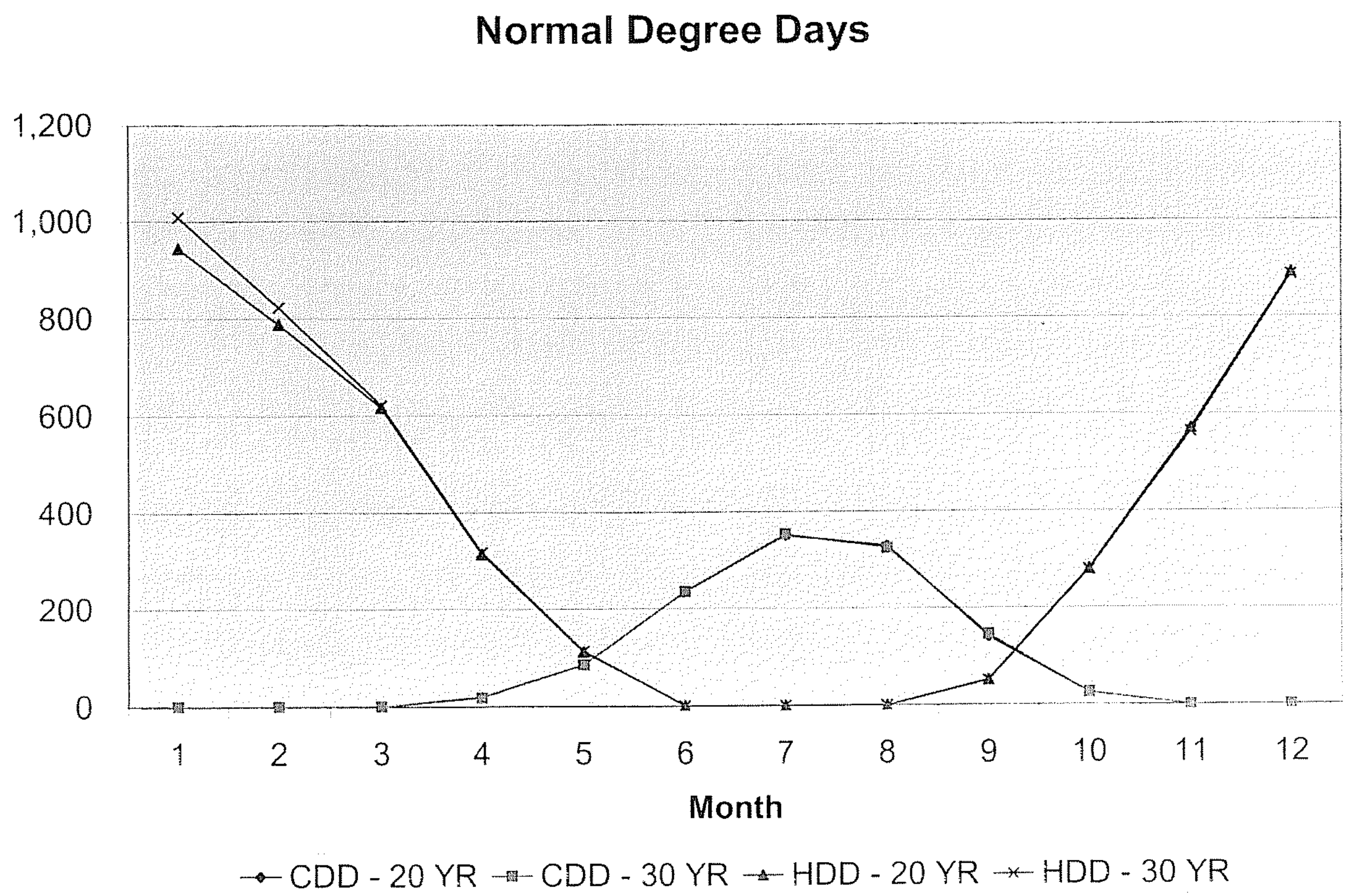
Index	Coefficient
1	HDD60
2	HDD65
3	CDD65
4	CDD70
5	MinTemp
6	MaxTemp
7	Open
8	Open

KU Classes

Index	Class	Class Description
1	1	RS
2	20	RS (formerly Full Electric)
3	100	C/I GS Sec
4	120	C/I GS Pri
5	140	C/I GS Schools
6	160	C/I GS Net Meter
7	200	C/I LP STOD Sec
8	210	C/I LP STOD Pri
9	300	C/I LP Sec
10	305	C/I LP Sec PF
11	320	C/I LP Pri
12	325	C/I LP Pri PF
13	345	C/I LP Trans PF
14	420	Lg C/I LCI-TOD Pri PF
15	440	Lg C/I LCI-TOD Trans PF
16	500	C/I Mines Pri
17	505	C/I Mines Pri PF
18	510	C/I Mines Trans
19	515	C/I Mines Trans PF
20	520	Lg C/I Mines LMP-TOD Pri PF
21	530	Lg C/I Mines LMP-TOD Trans P
22	615	Lg Ind LI-TOD Trans
23	700	Wholesale Municipal Pri
24	710	Wholesale Municipal Trans
25	720	Wholesale Municipal Paris
26	730	Wholesale ODP - VA
27	Street Ligh	Street Lighting
28	800	Company Use
29	Open	Open

LE Classes

Index	Class	Class Description
1	1	RS Sec
2	100	C/I GS Sec 1 ph
3	105	C/I GS Sec 3 ph
4	120	C/I GS Pri 1 ph
5	125	C/I GS Pri 3 ph
6	200	C/I LC STOD Sec
7	210	C/I LC STOD Pri
8	220	C/I LC Sec
9	230	C/I LC Pri
10	240	C/I LC Sec TOD
11	250	C/I LC Pri TOD
12	260	C/I LC Special
13	300	C/I LP Sec
14	320	C/I LP Pri
15	400	Lg C/I LP Sec TOD
16	420	Lg C/I LP Pri TOD
17	430	Lg C/I LP Pri TOD CSR
18	440	Lg C/I LP Trans TOD
19	450	Lg C/I LP Trans TOD CSR
20	600	Lg C/I Special
21	800	Company Use
22	Other OL	700
23	RS OL	700
24	Comm OL	700
25	PSL	710
26	SLE	720
27	TLE	730
28	Open	Open
29	Open	Open


Normal Degree Days
1,200
1,000
800
600
400
200
0
1
2
3
4
5
6
7
8
9
10
11
12
Month
CDD - 20 YR
CDD - 30 YR
HDD - 20 YR
HDD - 30 YR

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 65

Responding Witness: William Steven Seelye

Q-65. Provide, in electronic format with all formulae intact, the workpapers supporting Exhibits 11, 12 and 13 of the Seelye Testimony.

A-65. Please see the response to Question No. 30.

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 66

Responding Witness: William Steven Seelye

Q-66. For each rate class shown on Exhibit 15, page 1, of the Seelye Testimony, provide the number of customers for the end of each month used to calculate the 13-month average. If Exhibit 15 was determined using a 12-month average, provide a revised Exhibit 15 utilizing a 13-month average consisting of the number of customers at the beginning of the test year (May 1, 2006) and the ending of the test year (April 30, 2008).

A-66. Exhibit 15 was determined using a 13-month average. Please see the attached for number of customers for the end of each month.

	Apr-07	May-07	Jun-07	Jul-07	Aug-07	Sep-07	Oct-07	Nov-07	Dec-07	Jan-08	Feb-08	Mar-08	Apr-08	13-Month Average
Number of Customers														
Residential Rate - RS (Rate Code 010, 050)	222,987	222,820	222,464	222,754	222,549	222,198	222,522	222,351	222,464	223,385	222,496	222,410	221,917	222,563
Residential Rate - RS (Rate Code 020, 060, 080)	188,560	188,756	188,869	189,723	189,862	189,890	190,357	190,683	191,296	192,552	192,052	192,012	191,729	190,488
General Service - GS														
Secondary	77,203	77,346	77,627	77,851	77,765	78,031	78,349	78,242	78,338	78,680	78,633	78,768	78,790	78,125
Primary	74	74	72	72	73	74	73	73	73	72	72	72	72	73
All Electric Schools - AES	306	303	304	302	303	305	306	305	307	309	308	310	306	306
Large Power Rate - LP														
Secondary	9,233	9,187	9,139	9,052	9,028	8,971	8,954	8,876	8,847	8,833	8,778	8,707	8,673	8,944
Primary	350	350	351	351	351	350	348	349	349	349	348	348	349	349
Transmission	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Small TOD - Secondary	51	51	50	52	51	51	51	51	51	51	51	51	51	51
Small TOD - Primary	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Small TOD - Transmission	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Large Comm/Ind TOD														
Primary - LCI-TOD	38	38	39	39	40	40	40	40	40	40	40	40	40	40
Transmission - LCI-TOD	7	7	7	7	7	8	8	8	8	8	8	8	8	8
Large Industrial TOD	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Mine Power - MP														
Primary	30	29	29	30	27	30	30	36	28	34	31	29	31	30
Transmission	12	10	10	10	10	10	11	10	10	10	10	12	10	10
Large Mine Power - LMP TOD														
Primary	4	4	4	4	4	4	3	3	3	3	3	3	3	3
Transmission	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Number of Lights														
Street Lighting - SL	72,206	70,254	70,071	70,266	70,323	70,350	70,383	70,468	70,479	70,456	70,519	70,537	70,585	70,531
Decorative Street Lighting - SLDEC	5,627	20,853	7,673	7,705	7,778	7,793	7,886	8,007	8,053	8,139	8,175	8,186	8,206	8,775
Private Outdoor Lighting - POL	28,706	28,760	28,784	28,959	28,834	28,831	29,034	29,028	29,220	29,352	29,229	29,422	29,538	29,054
Customer Outdoor Lighting - OL	56,358	56,539	56,329	56,598	56,707	56,671	56,695	56,830	56,850	56,662	56,924	56,967	56,652	56,676
TOTAL	661,763	675,392	661,833	663,786	663,723	663,618	665,061	665,371	666,427	668,946	667,688	667,893	666,971	666,037

KENTUCKY UTILITIES COMPANY

CASE NO. 2008-00251
CASE NO. 2007-00565

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

Question No. 67

Responding Witness: William Steven Seelye

Q-67. Reconcile the "Current" Disconnect/Reconnect Charge as stated in Exhibit 6, page 2, of the Seelye Testimony in the amount of $1,008,440 to the amount recorded in account 451001 of $1,079,166 as shown in Volume 1 of 4 of the response to Staff's first request, Item 13, at page 10.

A-67. Current Disconnect/Reconnect Charge as stated in Exhibit 6, page 2 was calculated using actual number of disconnects and the disconnect charge. The amount in account 451001 is the jurisdictional sum of all journal entry amounts during the test year.