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PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

THE APPLICATION OF THE UNION LIGHT, HEAT AND POWER COMPANY D/B/A DUKE ENERGY KENTUCKY TO INCREASE ITS ELECTRIC RATES	)))	CASE NO. 2006-00172

ATTORNEY GENERAL'S SECOND REQUEST FOR INFORMATION TO
THE UNION LIGHT, HEAT AND POWER COMPANY D/B/A DUKE ENERGY KENTUCKY

Comes now the intervenor, the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention, and submits this Second Request for Information to Union Light, Heat and Power Company d/b/a Duke Energy Kentucky to be answered by the date specified in the Commission's Order of Procedure, and in accord with the following:

(1) In each case where a request seeks data provided in response to a staff request, reference to the appropriate request item will be deemed a satisfactory response.

(2) Please identify the witness who will be prepared to answer questions concerning each request.

(3) These requests shall be deemed continuing so as to require further and supplemental responses if the company receives or generates additional information within the scope of these requests between the time of the response and the time of any hearing conducted hereon.

(4) If any request appears confusing, please request clarification directly from the Office of Attorney General.

(5) To the extent that the specific document, workpaper or information as requested does not exist, but a similar document, workpaper or information does exist, provide the similar document, workpaper, or information.

(6) To the extent that any request may be answered by way of a computer printout, please identify each variable contained in the printout which would not be self evident to a person not familiar with the printout.

(7) If the company has objections to any request on the grounds that the requested information is proprietary in nature, or for any other reason, please notify the Office of the Attorney General as soon as possible.

(8) To the extent that the company has objections to any request for the provision of information on the grounds that doing so would violate Copyright laws, in lieu of the information requested, please state for the answer what efforts have been made by the company to secure permission to provide copies of the information requested for use in this case only. The response should include the name of the person to whom the request for permission to provide a copy of the document for use in this case was made, the date of the request, a copy of all documentation of the request and response, and the means by which the Attorney General might contact that person directly via telephone or electronically together with how and when the company will make the information available for inspection.

(9) For any document withheld on the basis of privilege, state the following: date; author; addressee; indicated or blind copies; all persons to whom distributed, shown, or explained; and, the nature and legal basis for the privilege asserted.

(10) In the event any document called for has been destroyed or transferred beyond the control of the company, please state: the identity of the person by whom it was destroyed or transferred, and the person authorizing the destruction or transfer; the time, place, and method of destruction or transfer; and, the reason(s) for its destruction or transfer. If destroyed or disposed of by operation of a retention policy, state the retention policy.

(12) Please provide written responses, together with any and all exhibits pertaining thereto, in one or more bound volumes, separately indexed and tabbed by each response.

Respectfully submitted,

GREGORY D. STUMBO
ATTORNEY GENERAL OF KENTUCKY

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NOTICE OF FILING AND CERTIFICATION OF SERVICE

I hereby give notice that I have filed the original and five true copies of the foregoing with the Executive Director of the Kentucky Public Service Commission at 211 Sower Boulevard, Frankfort, Kentucky, 40601 this the 9th day of August, 2006, and certify that this same day I have served the parties by mailing a true copy, postage prepaid, to the following:

SANDRA P MEYER
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DUKE ENERGY KENTUCKY INC
139 EAST FOURTH STREET
CINCINNATI OH 45202

JOHN J FINNIGAN JR ESQ
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Case No. 2006-00172
Attorney General's Second Request for Information
To Duke Energy Kentucky

1. In its response to AG-1-5, the Company states that the adjusted forecasted period depreciation expenses of $32,810,000 shown on Schedule B-3.2, represent the product of Mr. Spanos' proposed revised depreciation rates (shown in column F) to the average forecasted period depreciable plant in service. In its response to AG-1-5(a), the Company also states that ..."The $227,766 is the pro forma adjustment required to annualize the depreciation expense included in the unadjusted forecast to the revised depreciation rates proposed by the Company." In this regard, please provide the following information:

    a. Doesn't this mean that the unadjusted forecasted period depreciation expenses (that are based on the currently authorized depreciation rates as opposed to Mr. Spanos' proposed revised rates) amount to $32,810,000 less $227,766, or $32,582,234? If not, explain why not, given the above-referenced explanations included in the response to AG-1-5.
    b. If the assumption stated in part (a) above is incorrect, provide the forecasted period depreciation expenses calculated based on the currently authorized depreciation rates (i.e, under the assumption that Mr. Spanos' proposed depreciation rates will be rejected by the PSC).

2. The response to AG-1-8 shows monthly Non-Utility ADIT balances that are consistently decreasing to an actual balance of $74.6 million in June 2006, as compared to the originally projected increasing monthly Non-Utility ADIT balances, with a projected June 2006 ADIT balance of $77.989 million shown on WPB-6a. In this regard, please provide the following information:

    a. Explain the actual downtrend in this Non-Utility ADIT account and the reasons for the difference of $3.3 million between the actual and corresponding projected June 2006 balances.
    b. Based on the facts stated above, does the Company still believe that its projected average forecasted period Non-Utility ADIT balance of $76.495 million is accurate? If so, explain why the Company believes this. If not, provide the revised average forecasted period Non-Utility ADIT balance that the Company now projects based on the above-referenced variances as of June 2006.

3. With regard to the response to AG-1-16(e), please provide the following information:

    a. Actual electric ITC amortization for each of the years 2003 and 2004.
    b. Monthly breakout of the 2005 ITC amortization total of $176,447.
    c. Monthly ITC amortization for January through August 2006.

4. Similar to the response to AG-1-20(b), please provide the impact on the forecasted period East Bend property taxes of $750,000 assuming that the Company would be successful in obtaining an assessment value of 82.27% of the 2006 net book value.

5. With regard to the response to AG-1-4, do the Company's forecasted period electric "above-the-line" property taxes exclude the property taxes associated with the $24.1 million Non-Jurisdictional plant for the Florence service building and land? If so, identify this tax amount and confirm that this should be removed for ratemaking purposes.

6. With regard to the response to AG-1-24, please provide the following information:

   a. Provide your best estimate of the annualized incremental revenues of each of the new miscellaneous charges referenced in AG-1-24.
   b. Explain why the Company believes it is appropriate to propose additional miscellaneous revenue charges for the forecasted period without reflecting the projected forecasted period revenues from these additional miscellaneous revenue charges.

7. With regard to the Company's Emission Allowance Sale Proceeds, please provide the following information:

   a. Explain whether the Company will now be receiving such proceeds as a result of the 1/1/06 transfer of the Plants and that prior to 1/1/06 these proceeds were received and booked on the books of Duke Energy Ohio (DEO). If this is not correct, provide a detailed explanation of the correct facts.
   b. Provide the actual Account 411 Emission Allowance Sale Proceeds associated with the Plants in each of the years 2003, 2004, 2005 and the 12-month period ended June or July 2006. Provide this annual proceeds information no matter whether the Plants were owned by DEO or DEK.
   c. Since the Company does not budget such proceeds, does the $2,133,750 Base Period proceeds amount represent the actual proceeds for the 6-month period 9/1/05 – 2/28/06? If not, provide the correct information and provide the $2,133,750 on a monthly basis.
   d. Would the Company agree that Emission Allowance Sale proceeds, if known and measurable, should be treated "above-the-line" for ratemaking purposes. If not, explain in detail why not and, in that case, explain why the Company is requesting that the Emission Allowance inventory be included for ratemaking purposes in this case.

8. With regard to the Other Operating revenues for RSG Revenue – MISO Make Whole, please provide the following information:

   a. Since which date (month and year) did the Company start receiving such revenues and explain why.

b. Provide the actual RSG Revenue – MISO Make Whole revenues on a monthly basis since the Company starting receiving these revenues through July 2006.

c. Would the Company agree that, if known and measurable, the RSG Revenue – MISO Make Whole revenues should be treated "above-the-line" for ratemaking purposes? If not, explain in detail why not.

9. With regard to the response to AG-1-26, please provide the following information:

a. Explain why the Company did not book Account 454010 – Rent Elec Land and Buildings revenues in 2003 – 5/31/06 while it has budgeted $45,000 and $91,356 of such revenues for the Base and Forecasted Periods.

b. What represents Account 456865 – I/C Transmission Revenue EM revenues; how is it different from Account 456855 – I/C Transmission revenues; and why has the Company not reflected any Account 456865 revenues in the Base and Forecasted Periods.

c. Re. Account 454100: When did the Company start receiving the pole contract lease revenues; provide these revenues on a monthly basis from the time the Company starting booking them through July 2006; and explain whether the pole contracts underlying these revenues are still in place today and are expected to be in place during the Forecasted Period.

d. Re. Account 454710: When did the Company start receiving these rent revenues; provide these rent revenues on a monthly basis from the time the Company starting booking them through July 2006; and explain whether the lease contract underlying these rent revenues is still in place today and is expected to be in place during the Forecasted Period.

e. Re. Account 456350: When did the Company start receiving these fuel management revenues; provide these revenues on a monthly basis from the time the Company starting booking them through July 2006; and explain whether the Company is currently still booking these revenues and is expected to continue to book these revenues in the near-term future.

10. Is there an allowance in the Company's FAC rate for the recovery of the PSC assessment fees and uncollectibles associated with the fuel adjustment clause revenues? If not, how are these fuel revenue related fees and expenses recovered by the Company?

11. Re. response to AG-1-48: the adjusted forecasted period uncollectible expense of $867,292 represents a ratio of approximately .30% of the total associated forecasted period revenues subject to uncollectibles of $288,693,617 (see WPD-2.31a). Since this is the effective uncollectible ratio for the forecasted period, why shouldn't this ratio of .30% be included in the gross revenue conversion factor rather than the ratio of .5493% currently reflected by the Company? Please comment in detail.

12. With regard to the response to AG-1-47, please provide the following information:

a. Does the response shown on Attachment AG-1-47(a) mean that the Company's projected base period expenses of $1,052,644 and forecasted period expenses of $1,894,366 would be $904,752 and $1,413,816, respectively, without the impact of the transfer of the three plants? Or does it mean that the Company's projected base period expenses of $1,052,644 and forecasted period expenses of $1,894,366 would be $147,892 ($1,052,644 - $904,752) and $480,550 ($1,894,366 - $1,413,816), respectively, without the impact of the transfer of the three plants?

b. In the same format as per Attachment AG-1-47(a), provide the actual Professional Services expenses for the 12-month period ended June 30, 2006, as well as for the 6-month period 1/1/06 – 6/30/06. In addition, identify what both of these 12-month and 6-month dollar amounts would be excluding the impact of the transfer of the three plants.

13. With regard to the response to PSC-2-101, please provide the following information:

a. Duke Energy Kentucky's actual effective state income tax rates from its consolidated state income tax filings for each of the years 2001 – 2005.

b. The actual effective federal income tax rates from Cinergy's (and, since the merger, Duke Energy's) consolidated income tax filings for each of the years 2001 – 2005.

14. With regard to the responses to PSC-2-99 and PSC-1-18, please provide the following information:

a. The response to PSC-1-18 refers to an Attachment which the AG did not receive. Please provide a copy of this Attachment.

b. Confirm that the estimated 2007 labor savings of $1,226,000 represent recurring annual cost savings and that the separation costs of $385,100 represent one-time costs.

c. Provide all evidence in support of the Company's claim that the early retirement plans and employee reduction programs in question are a direct result of the merger with Duke Energy and that the cost savings from these programs are included in the negotiated Merger Savings Credit.

d. Is it the Company's position that all future employee reduction initiatives to be implemented by Duke Energy will be a direct result of the merger and will have been included in the negotiated Merger Savings Credit?

15. Please explain the nature and purpose of the Economic Assistance Program expenses of $2,018 (forecasted period) shown in the response to PSC-2-21.

16. Please provide a detailed breakout of all association dues and fees making up the total actual amount of $130,633 for the 12-month period ended 5/31/06 and the total forecasted period amount of $181,260. In addition, explain the reason for the increase.

17. With regard to the response to AG-1-53, please provide the following information:

a. Actual EPRI membership dues booked in 2001, 2002, 2005 and the most recent 12-month period for which actual data are available.
b. Reason why the Company did not expense such dues in 2003 and 2004 (and, if applicable, in the other years referenced in part a) while projecting such expenses for the forecasted period.
c. Basis for the projected forecasted period expenses of $77,228.

18. With regard to the Company's PSA Back-Up related competitive bidding process, please provide the following information:

a. When will the final results from this bidding process be known and certain?
b. Does the currently reflected projected PSA Back-up capacity charge of $10,431,923 for the forecasted period serve as a "placeholder" cost amount at this time that would be replaced by the final "lowest cost and best supply option" (Esamann testimony, page 6, lines 8-10) produced by the competitive bidding process that is expected to be completed in July 2006? Please explain.

19. With regard to the testimony of Mr. Wathen, page 21, lines 7 – 9, what would the currently filed NITS expense reduction of $4,187,956 be based on the use of an ROE rate of 10.5% (as opposed to Dr. Morin's recommended ROE rate of 11.5%), as well as based on the use of an ROE rate of 9.5%.

20. With regard to the response to PSC-1-20, please provide the following information:

a. Do the employee numbers in the Forecasted Period column represent the full-time employee equivalent of the electric labor hours budgeted for the Forecasted Period that formed the basis for the total forecasted period electric labor cost of $28,554,063 [see FR 10(9)(h)(10)]? If not, provide the correct facts.
b. Provide the equivalent electric operations employee numbers on an actual basis for each of the months 2006 through June 2006 (or July 2006,if available).
c. The response to PSC-1-20 indicates an average monthly electric operations employee level of 228 for the forecasted period. Please compare this projected forecasted period employee level of 228 (which presumably includes the full impact of any electric employees that came with the transfer of the plants) to the average actual electric employee levels for the first 6 months of 2006 to be provided in response to part b above (which presumably also includes the full impact of any electric employees that came with the transfer of the plants) and explain any difference between these two average electric employee levels.

21. FR 10(9)(h)(10) indicates electric O&M expense ratios (ratio of electric labor O&M expenses to total electric labor costs) for 2006 of 77.67% and for the 2007 forecasted period of 79.07%. The response to AG-1-63 shows that the comparable electric labor O&M expense ratio for the 12-month period ended 5/31/06 is 73%. In this regard, please provide the following information:

a. Provide the equivalent actual electric labor cost data and O&M expense ratios for the 12-month period ended June 30, 2006 and for the 6-month period ended June 30, 2006.

b. Compare the two actual electric labor O&M expense ratios to be provided in response to part a above to the projected electric labor O&M expense ratio of 79.07% assumed for the forecasted period and provide explanations for the differences.

22. With regard to the response to AG-1-74, please provide the following information:

a. In the same format and detail as per the response to AG-1-74(b), provide the actual monthly and total employee benefit O&M expenses for the 12-month period ended June 30, 2006.

b. Provide explanations for the differences between the actual annual employee benefit O&M expenses to be provided in the response to part a above (which covers a period that only excludes 2 months of the base period) and the corresponding base period employee benefit O&M expenses shown in the response to PSC-1-19(a).

c. Please provide explanations for the differences between the projected employee benefit O&M expense components for the forecasted period (shown on Attachment AG-1-74c) and the annualized (use multiple of 2x) actual employee benefit O&M expenses for the first 6 months of 2006.

23. Various portions of the response to AG-1-70 are still not clear to the AG. Please provide the following additional explanations:

a. The response to AG-1-70(a) appears to indicate that the total MISO related transmission expenses that are included in the forecasted period amount to $16,939,554. Please confirm this and reconcile this amount with the amount of $21,876,213 referenced in the response to AG-1-70(d).

b. The response to AG-1-70(c) states that "only costs billed from the Midwest ISO are eligible for recovery in the TCRM." In this regard, please provide the following additional information:

1) What is the amount of such "costs billed from the Midwest ISO" included in the forecasted period.

2) Indicate where these specific costs are included in the $16,939,554 total transmission costs shown at the top of Attachment AG-1-79(a).

3) Does this mean that a portion of the total MISO related transmission expenses of $16,939,554 is not eligible for inclusion in the TCRM Rider? If so, reconcile this with the Company's statement in its response to PSC-2-42(a) that the Company …" is requesting the ability to timely recover all MISO-related transmission costs" [in Rider TCRM].

c. The Company's response to AG-1-70(d) does not clearly respond to what was requested in AG-1-70(d): Schedule L-2.2, page 71 of 88 shows that the Rider TCRM-eligible transmission costs included in the Base Year are $12,047,693.

Please provide the equivalent amount of Rider TCRM-eligible transmission costs that are included in the Forecasted Period.

24. Please describe the allocation methodologies that are different in the pre-merger compared to the ones used in the post-merger as stated in response to KyPSC-DR-02-007, part a, the first sentence.

25. Please describe the additional allocation methodologies which were implemented as stated in response to KyPSC-DR-02-007, part a, in the second sentence.

26. Refer to page 37 of 95 of Attachment AG-DR-01-139.

a. Explain why "we didn't sell 100% of these units to ULH&P." What are the exceptions and why are there any exceptions? State whether the KPSC and other parties were made aware of these exceptions in connection with the transfer.
b. Why are the production assets "just transferring in January [2006] business"? What took so long?
c. Provide complete copies of the transfer journal entries, and detailed explanations of each entry.
d. Identify all reserves transferred with the production units.
e. Identify all legal AROs and all non-legal AROs transferred with the production units.

27. Refer to page 38 of 95 of Attachment AG-DR-01-139.

a. Explain in detail the following statement from Brenda Martinez to John Spanos, "John, also, the UHL&P electric production is going to be regulated so we will be able to incorporate a COR component unlike the CG&E assets that are deregulated. So, we will need the rates developed with the COR separated."
b. Specifically identify the UHL&P and CG&E assets to which Ms. Martinez refers, and explain where they can be specifically found in Mr. Spanos' depreciation study.
c. Explain why deregulated assets do not incorporate a COR component?
d. Does this statement relate in any way to SFAS No. 143, FIN 47, FERC Order No. 631?

28. Provide any and all internal studies and correspondence concerning the Company's implementation of FASB Statement No. 143, the FERC NOPR and Order No. 631 in RM-02-7-000, and FIN 47.

29. Provide complete copies of all correspondence with the following parties regarding the Company's implementation of FASB Statement No. 143, FIN 47 and the FERC NOPR and Order 631 in RM02-7-000:

a. External auditors and other public accounting firms.

b. Consultants
c. External counsel
d. Federal and State regulatory agencies
e. Internal Revenue Service

30. Regarding FASB Statement No. 143, FIN 47, and the FERC NOPR and Order No. 631 in Docket No. RM02-7-000, on a plant account-by-plant account basis, please identify any and all "legal obligations" associated with the retirement of the assets contained in the account that result from the acquisition, construction, development and (or) the normal operation of the assets in the account. For the purposes of this question, use the definition of a "legal obligation" provided in FASB Statement No. 143: "an obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract under the doctrine of promissory estoppel."

31. For any asset retirement obligations identified above, please provide the "fair value" of the obligation. For the purposes of the question, fair value means "the amount at which that liability could be settled in a current [not future] transaction between willing parties, that is, other than in a forced or liquidation transaction." Provide all assumptions and calculations underlying these amounts.

32. Provide complete copies of all Board of Director's minutes and internal management meeting minutes during the past five years in which any or all of the following subjects were discussed: the Company's electric plant depreciation rates; retirement unit costs; SFAS No. 143; FIN 47; and, FERC RM02-7-000.

33. Refer to page 138 of ULH&P's December 31, 2005 Form 10K. Provide the accounting entries (debits and credits) used to implement SFAS No. 143 and FIN 47, along with all workpapers supporting those entries, including the workpapers supporting the calculation of the $29 million (2005) and $30 million (2004) regulatory liabilities for asset cost of removal. Please provide all these workpapers and calculations in electronic format (Excel) with all formulae intact.

34. Please provide a complete explanation for why the regulatory liability for cost of removal decreased from $30 million in 2004 to $29 million in 2005. Provide all accounting entries related to this decrease. Also, please provide the workpapers and calculations supporting those entries in electronic format (Excel) with all formulae intact.

35. Provide an analysis of the regulatory liability for cost of removal since inception identifying and explaining each debit and credit entry and amount.

36. What impact did the application of FIN 47 have upon the proposed depreciation rates and expense in this rate case? Provide all workpapers supporting the answer. If the answer is "none", provide workpapers supporting that statement.

37. Provide ULH&P's projection of the annual year-end balance in the regulatory liability for non-legal AROs shown in its Form 10K, for the next 20 years. If not available for the next twenty years provide for as many years into the future that the projection is available. If this projection has not been made, please explain why not.

a. For this projection assume that all of ULH&P's proposed depreciation rates are approved as requested. Provide in hard copy and in electronic format with all formulae intact.
b. Explain all assumptions used to make this projection.

38. With respect to the Regulatory Liability relating to asset cost of removal which you reclassified out of accumulated depreciation:

a. Do you agree that this constitutes a regulatory liability for regulatory purposes in Kentucky and for FERC purposes? If not, please explain why not.
b. Do you agree that this amount is a refundable obligation to ratepayers until it is spent on its intended purpose (cost of removal)? If not, why not?
c. Please explain the repayment provisions associated with this regulatory liability.
d. Explain when you expect to spend this money for cost of removal.
e. Explain what you have done with this money as you have collected it. If you say that you have spent it on plant additions, please prove it.
f. Identify and explain all other similar examples of ULH&P's advance collections of estimated future costs for which it does not have a legal obligation.
g. Does ULH&P agree that the Kentucky Public Service Commission will never know whether or not ULH&P will actually spend all of this money for cost of removal until and if ULH&P goes out of business? If not, why not?
h. Does ULH&P believe that amounts recoded in accumulated depreciation represent capital recovery? If not, why not?
i. Whose capital is reflected in accumulated depreciation – shareholders' or ratepayers'?

39. For all accounts for which ULH&P has collected non-legal AROs, but instead recorded a regulatory liability, please provide the fair value of the related asset retirement cost as of December 31, 2002; December 31, 2003, December 31, 2004 and December 31, 2005. For the purposes of this question, assume that ULH&P has legal AROs for these accounts, and use the life and dispersion assumptions reflected in Mr. Spanos's depreciation study.

40. Provide the calculation of the annual amount of future net salvage incorporated into ULH&P's existing depreciation rates and in its proposed depreciation rates by account. If the amount is reduced by the total amount of non-legal AROs included in year-end accumulated depreciation, show that calculation.

41. Is ULH&P fearful that if the non-legal regulatory liability is highlighted, as SFAS No. 143 and FERC Order No. 631 have done; someone will attempt to make companies such

as ULH&P refund the prior collections? If not please explain the industry's primary concern, if ULH&P is aware of that concern. Provide all documents upon which ULH&P relies to respond to this question.

42. Refer to page 40 of 95 of Attachment AG-DR-01-139.

    a. Explain why Wheatland is not being brought onto the books at Allegheny's NBV? Also, explain why Wheatland is being brought onto the books at FMV?

    b. Provide the calculation of the Wheatland FMV.

43. Refer to page 95 of 95 of Attachment AG-DR-01-139. Provide an unredacted copy.

44. Refer to page 8 of 15 of Attachment AG-DR-01-142 (b).

    a. Explain Bullet[s] 1, 2 and 3 in detail, and provide all documents resulting therefrom.

    b. Provide all current depreciation rates for non-regulated capital asset accounts.

    c. Provide all GAAP depreciation rates, by account.

45. Refer to page 10 of 15 of Attachment AG-DR-01-142(b).

    a. Explain what a "fluctuation analysis" is.

    b. Provide all fluctuation analyses conducted in 2004, 2005, and 2006 to date relating to "additions, impairments, retirements and depreciation."

    c. Provide all "Thresholds for account variances requiring written explanations."

46. Refer to page 12 of 48 of Attachment AG-DR-01-144.

    a. Explain item number "4)" at the top of the page in the 4/17/06 email from James Dean to Carl J. Council. Identify all related impacts emanating from "the transfer from non-reg CGE to reg UHLP."

47. Refer to pages 14 to 20, 30 to 33, 39 of 48 of Attachment AG-DR-01-144. Provide unredacted copies.

48. Refer to page 36 of 48 of Attachment AG-DR-01-144. Provide Lisa Carver's response to the 9 questions in Carl Council's May 4, 2006 email.

49. Refer to response to AG-DR-01-173. You state, "It would be premature to develop any more specific plans to retire and dismantle production plant at this time."

    a. Did you use the life span procedure for these plant accounts and locations?

50. For all accounts and locations for which the life span method is proposed, provide the following information to support the final retirement dates. Please respond to each item.

a. Economic studies. (NARUC, p. 146)
b. Retirement plans. (NARUC, p. 146)
c. Forecasts. (NARUC, p. 146)
d. Studies of technological obsolescence. (NARUC, p. 146)
e. Studies of adequacy of capacity. (NARUC, p. 146)
f. Studies of competitive pressure. (NARUC, p. 146)
g. Relationship of type of construction to remaining life span.
h. Relationship of attained age to remaining life span.
i. Relationship of observed features and conditions at the time of field visits to remaining life span.
j. Relationship of specific plans of management to remaining life span.

51. Identify all circumstances unique to Kentucky which influence or have an impact on the life span estimates.

52. In response to Kroger and St. Elizabeth Medical Center DR-01-018 and PSC DR-02-081 the Company proposes an alternative Rider DSM recovery of PowerShare CallOption expenses in the event the Commission determines those expenses are not subject to recovery via the fuel adjustment clause under 807 KAR 5:056.

a. Where in this application is the analysis required by KRS 278.285?
b. What classes are expected to benefit from the program and to what classes are the costs to be assigned?
c. Under Kentucky law, where is the resale of electric power to the utility by its customer authorized or permitted?

53. As a regulated state under which rates for generation, transmission and distribution are bundled, compare Kentucky customers to customers in Ohio under its rate structure with reference to transmission costs.

54. Please explain the basis on which the Green Power program, in which the risks and rewards of the offering are below the line, is a utility service for the purposes of KRS Chapter 278. Include in your response the specific statutory authority that authorizes Duke Energy Kentucky to provide a Green Power program, the risks and rewards of which are all below-the-line, to its regulated captive utility customers and that permits it to charge its regulated customers more for the utility services provided than the cost of power.

55. In response to PSC-02-019 the benefits of the proposed AMI program for electric customers is described, but according to the cost analysis it is to be for gas customers as well as electric or combined customers. Please explain the benefit of the program to gas customers.