Joint Intervenors' Exhibit A

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE 8-1-8.5 AND 8-1-8.7; AND (2)AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPLICABLE RELATED COSTS AND CREDITS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE §§ 8-18-.8-11 AND -12	:	**CAUSE NO.43114-IGCC-12/13**

PUBLIC
DIRECT TESTIMONY OF

RALPH C. SMITH

ON BEHALF OF

CITIZENS ACTION COALITION OF INDIANA, INC., HOOSIER CHAPTER OF THE SIERRA CLUB, SAVE THE VALLEY, INC., AND VALLEY WATCH, INC.

December 15, 2014

DIRECT TESTIMONY OF RALPH C. SMITH
TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. PURPOSE AND SCOPE OF TESTIMONY 11

III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS 13

IV. "COMMERCIAL OPERATION" OF THE EDWARDSPORT IGCC DID NOT OCCUR DURING THE COMBINED IGCC-12 AND 13 REVIEW PERIODS 17

V. NEED FOR PERFORMANCE STANDARDS AND AN OPERATING COST CAP TO PROTECT RATEPAYERS FROM EXCESSIVE COSTS AND POOR PLANT PERFORMANCE 40

VI. UNREASONABLY HIGH COST OF THE EDWARDSPORT IGCC DURING THE IGCC-12 AND 13 REVIEW PERIODS 48

VII. CONCERN THAT DEI IS CLASSIFYING COSTS IN A MANNER TO EVADE THE "HARD COST CAP" AND THAT IS INADEQUATELY DOCUMENTED, NOT TRANSPARENT AND CANNOT BE ADEQUATELY REVIEWED 54

VIII. COMMISSION ORDERED REFUND AND CARRYING COSTS ON RATEPAYER MONIES BEING HELD BY THE COMPANY 66

IX. THE NEED FOR ADDITIONAL PROCEEDINGS 70

X. CONCLUSION 72

EXHIBITS:

LA-1, Background and Qualifications

LA-2, Section 2 and related Attachments of the April 30, 2012 Settlement Agreement approved in Cause No. 43114-IGCC-S1

LA-3, Responses to CAC 4.4 through 4.7 in Cause No. 43114-IGCC-8

LA-4, DEI’s August 11, 2014 Supplemental Response to DEI-IG 1.4 in this proceeding concerning the meaning of certain terms used in Exhibit LA-2, Section 2 and related Attachments of the IGCC-4S1 Settlement Agreement

LA-5, FERC Uniform System of Accounts Electric and Gas Instruction No. 3

LA-6, FERC Uniform System of Accounts Electric and Gas Instruction No. 4

LA-7, FERC Uniform System of Accounts Electric and Gas Instruction No. 9D

LA-8, FERC Uniform System of Accounts Electric and Gas Instruction No. 9E

LA-9, FERC Accounting Release AR-5, “Capitalization of Allowance for Funds Used During Construction”

LA-10, FASB Accounting Standards Codification section 360-10-30

LA-11, Industrial Group Cross Examination Exhibits IG-CX-2, IG-CX-4, and IG-CX-5 from IGCC-11

LA-12, Estimated Cost to Customers per kWh of Edwardsport IGCC through March 31, 2014 (Contains Petitioner-designated CONFIDENTIAL information on net generation from the Edwardsport IGCC)

LA-13, Estimated IGCC-12/13 Revenue Requirement Adjustment for Edwardsport IGCC Not Being in Commercial Operation During the IGCC-12/13 Review Period

LA-14, Estimated Performance Adjustment for Edwardsport IGCC for the IGCC-12/13 Review Period

LA-15, Estimated Adjustment for Excessive Operating Expenses During the IGCC-12/13 Review Period

LA-16, A copy of Petitioner's response to CAC 2.1

LA-17, Petitioner's CONFIDENTIAL responses to DEI-IG 4.24 and DEI-IG 6.1d

LA-18, A copy of the April 24, 2012 Order in Case No. 2009-UA-01 (Final Order on Remand), where the Mississippi Public Service Commission articulated its conceptual framework in the context of the Kemper IGCC that is being constructed by Mississippi Power Company to protect Mississippi ratepayers from potential poor operational performance

LA-19, Petitioners' response and supplemental response to CAC 10.2 and Petitioner's response to CAC 10.6

LA-20, Petitioner's December 5, 2014 Supplemental Response to DEI-IG 1.8

LA-21, Petitioner’s Responses to DEI-IG 4.8, DEI-IG 4.9, and DEI-IG 4.10

LA-22, Petitioner’s Response to DEI-IG 4.14

LA-23, Petitioner’s Response to DEI-IG 4.31

LA-24, Petitioner’s October 13, 2014 Supplemental Response to DEI-IG 3.6

LA-25, Petitioner’s CONFIDENTIAL Response to CAC 6.38

LA-26, Petitioner’s Responses to DEI-IG 6.4 and DEI-IG 6.5

LA-27, Copy of Company witness Diana Douglas’s Workpaper 12 from IGCC-12

LA-28, Petitioner's Response to CAC 10.16 and Attachment 10.16-A

LA-29, Petitioner's Responses to CAC 18.28 and CAC 18.29

LA-30, Petitioner's Responses to CAC 22.3 and Confidential Attachment 22.3-A

LA-31, Petitioner's Responses to CAC 22.4 and Confidential Attachment 22.4-A

LA-32, Petitioner's Responses to CAC 25.2 (not including bulk attachment)

LA-33, Petitioner's Responses to CAC 18.8 through CAC 18.27

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the

Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 35 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning numerous electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South

Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law. My prior testimony has included evaluations of numerous utility rate case filings and revenue requirement determinations.

Q. Have you prepared an exhibit summarizing your educational background and regulatory experience?

A. Yes. This is provided in Exhibit LA-1.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by Joint Intervenors, Citizens Action Coalition of Indiana, Inc., Hoosier Chapter of The Sierra Club, Save the Valley, Inc., and Valley Watch, Inc., to address certain issues presented in IGCC-12 and 13 concerning the Edwardsport Integrated Gasification Combined Cycle generating facility ("IGCC Project" or "Project"). Accordingly, I am appearing on behalf of Joint Intervenors.

Q. What was the status of the IGCC Project during the IGCC-12 and 13 review periods?

A. The IGCC Project was still under construction by Duke Energy Indiana ("Petitioner," "Duke," "DEI," or "Company") at the beginning of the IGCC-12 review period of April through September 2013. DEI declared the Edwardsport IGCC to be "in service" on June 7, 2013 for accounting and ratemaking purposes. However, as explained herein and in the testimony of Mr. Schlissel, the IGCC Project was still being tested prior to its substantial completion during the October 2013 through March 2014 IGCC-13 review period. Following the Company declaring it "in service" in June 2013 and continuing through the end of the combined IGCC-12 and 13 review periods, the evidence shows that the Edwardsport IGCC was not available on syngas at or near its rated capacity for economic dispatch by the Midcontinent Independent System Operator ("MISO"), despite the Company's claims that it was in "commercial operation" during this period. The Company stated in its October 1, 2014 supplemental response to discovery, such as DEI-IG 1.8, that the date of final completion has not yet been achieved: "Given that Substantial Completion (as defined in the Duke/GE contract) has not yet occurred, it is difficult to estimate when Final Completion will occur." The Company's October 1, 2014 supplemental response to DEI-IG 1.8 states that: "Substantial Completion (as defined in the Duke/GE contract) has not yet occurred, therefore it is continues to be difficult to estimate when Final Completion will occur."[1]

Additionally, the cost per MWh (and per kWh) to Indiana ratepayers of the IGCC Project from the Company's declared "in service" date through the end of the combined IGCC-12 and 13 review periods was extremely high. Moreover, as addressed in the testimony of Joint Intervenors witness Schlissel, during the combined

[1] As discussed in the direct testimony of Joint Intervenors witness Schlissel, the Company updated this information on December 5, 2014 with a further Supplemental Response to DEI-IG 1.8, and now expects that substantial completion will not occur until the spring of 2015:

> The performance test and ramping demonstrations are complete with Duke Energy Indiana taking exception to certain adjustments made by GE to the heat rate calculation from the performance test. Duke Energy has reserved its rights and remedies under the Duke Energy/GE Contract, but accepts the performance test as complete because if GE is correct in its adjustments, the heat rate guarantee has been met. There is no dispute about the MW guarantee having been met. The ramp demonstration has been successfully completed. GE and Duke Energy have discussed and agreed upon a Punch List, subject to contractual remedies for any remaining items in dispute. The parties are currently discussing Documentation and a certificate of substantial completion, and anticipate that Substantial Completion will be achieved before the end of 2014. Thereafter, upon completion of the Punch List and further certification, Final Completion will have been achieved. The parties currently anticipate that this will occur in the spring of 2015 as certain Punch List items require a full station outage to be completed.

IGCC-12 and 13 review periods, the IGCC Project continued to experience serious operational problems, and the unreasonably low levels of generation from the Edwardsport IGCC during this period was not consistent with expectations of commercial operation.

Q. Have you previously filed testimony before the Indiana Utility Regulatory Commission ("IURC" or "Commission")?

A. Yes. I have previously filed testimony before the IURC in Cause Nos. 37352, 37353, 37354, 38431, 37396, 37394 and 37399, each of which involved gas cost adjustment reviews. I filed testimony and testified in the recent Indiana-American Water Company rate case, Cause No. 44022 and filed testimony in the recent Indiana Michigan Power Company rate case, Cause No. 44075. I also filed testimony on behalf of the Joint Intervenors in Cause Nos. 43114 IGCC-4S1, 43114 IGCC-10, and 43114 IGCC-11.

Q. How will your testimony be organized?

A. My testimony is organized into the following sections:

II. PURPOSE AND SCOPE OF TESTIMONY
III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS
IV. "COMMERCIAL OPERATION" OF THE EDWARDSPORT IGCC DID NOT OCCUR DURING THE COMBINED IGCC-12 AND 13 REVIEW PERIODS
V. NEED FOR PERFORMANCE STANDARDS AND AN OPERATING COST CAP TO PROTECT RATEPAYERS FROM EXCESSIVE COSTS AND POOR PLANT PERFORMANCE
VI. UNREASONABLY HIGH COST OF THE EDWARDSPORT IGCC DURING THE IGCC-12 AND 13 REVIEW PERIODS
VII. CONCERN THAT DEI IS CLASSIFYING COSTS IN A MANNER TO EVADE THE "HARD COST CAP" AND THAT IS INADEQUATELY DOCUMENTED, NOT TRANSPARENT AND CANNOT BE ADEQUATELY REVIEWED
VIII. COMMISSION ORDERED REFUND AND CARRYING COSTS ON RATEPAYER MONIES BEING HELD BY THE COMPANY
IX. THE NEED FOR ADDITIONAL PROCEEDINGS

X. CONCLUSION

Q. Does your direct testimony include any exhibits?

A. Yes, Exhibits LA-1 through LA-33.

Q. What is contained in Exhibit LA-1?

A. Exhibit LA-1 provides details concerning my experience and qualifications.

Q. What is shown in Exhibit LA-2?

A. Exhibit LA-2 contains a copy of Section 2 and related Attachments of the April 30, 2012 Settlement Agreement approved (with modifications only one of which is relevant to Section VIII of my testimony here) in Cause No. 43114-IGCC-S1.

Q. What is shown in Exhibit LA-3?

A. Exhibit LA-3 contains a copy of the Company's responses to data requests CAC 4.4 through 4.7 in Cause No. 43114-IGCC-8 concerning the commercial operation "in service" date that is referenced in my testimony.

Q. What is shown in Exhibit LA-4?

A. Exhibit LA-4 contains a copy of the Company’s response and 8-11-14 supplemental response to data request DEI-IG 1.4 in this proceeding concerning the meaning of certain terms used in Exhibit LA-2, Section 2 and related Attachments of the IGCC-4S1 Settlement Agreement.

Q. What is shown in Exhibit LA-5?

A. Exhibit LA-5 is a copy of FERC Uniform System of Accounts Electric and Gas Instruction No. 3.

Q. What is shown in Exhibit LA-6?

A. Exhibit LA-6 is a copy of FERC Uniform System of Accounts Electric and Gas Instruction No. 4.

Q. What is shown in Exhibit LA-7?

A. Exhibit LA-7 is a copy of FERC Uniform System of Accounts Electric and Gas Instruction No. 9D.

Q. What is shown in Exhibit LA-8?

A. Exhibit LA-8 is a copy of FERC Uniform System of Accounts Electric and Gas Instruction No. 9E.

Q. What is shown in Exhibit LA-9?

A. Exhibit LA-9 is a copy of FERC Accounting Release AR-5, "Capitalization of Allowance for Funds Used During Construction."

Q. What is shown in Exhibit LA-10?

A. Exhibit LA-10 is a copy of FASB Accounting Standards Codification section 360-10-30.

Q. What is shown in Exhibit LA-11?

A. Exhibit LA-11 is a copy of Industrial Group Cross Examination Exhibits IG-CX-2, IG-CX-4, and IG-CX-5 from IGCC-11. These are used for a comparison of Edwardsport IGCC operating expenses. These documents were admitted during the afternoon hearing in IGCC-11 on December 11, 2013, as NON-confidential exhibits at page B-29 of the Transcript. IG-CX-5, for example, was identified there as: "INTERVENOR'S IG EXHIBIT NO. CX-5, BEING A FIVE-PAGE DOCUMENT ENTITLED "DUKE ENERGY INDIANA, INC. ESTIMATED RETAIL REVENUE REQUIREMENT APPLICABLE TO THE EDWARDSPORT IGCC FACILITY (100% OWNERSHIP) (DOLLARS IN THOUSANDS)", ADMITTED INTO EVIDENCE." It is being attached to my testimony here for ease of reference.

Q. What is shown in Exhibit LA-12?

A. Exhibit LA-12 presents a calculation showing the Estimated Cost to Customers of Edwardsport IGCC through March 31, 2014 in total and on a per-MWh and per-kWh basis, based on Edwardsport cumulative retail customer charges and plant net generation for the plant through March 31, 2014.

Q. What is shown in Exhibit LA-13?

A. Exhibit LA-13 presents a calculation showing an Estimated IGCC-12/13 Revenue Requirement Adjustment for Edwardsport IGCC Not Being in Commercial Operation During the IGCC-12/13 Review Period. This calculation does not incorporate additional return on CWIP from additional post June 7, 2013 AFUDC accruals, which Petitioner may claim that it is entitled to under the terms of the Settlement Agreement. The impact of potential additional AFUDC has not been quantified, but if additional AFUDC were to be allowed by the Commission, that would lower the amount of the cost disallowance related to the Edwardsport IGCC not being in commercial operation during the combined IGCC 12/13 review periods.

Q. What is shown in Exhibit LA-14?

A. Exhibit LA-14 presents an Estimated Performance Adjustment for Edwardsport IGCC for the IGCC-12/13 Review Period. This adjustment is based on Joint Intervenors witness Schlissel's findings that the plant performed very poorly during the IGCC - 12/13 review period and achieved only 45 percent of the performance that Petitioner represented that the plant would produce during initial months of commercial operation.

Q. What is shown in Exhibit LA-15?

A. LA-15 presents an Estimated Adjustment for Excessive Operating Expenses During the IGCC-12/13 Review Period. This adjustment is based on a comparison of

Petitioner's reported actual operating expenses during the portion of the IGCC-12/13 review period when Petitioner has claimed that the Edwardsport IGCC was in commercial operation versus the previous presentation of estimated operating expenses for the first year of plant operation that is contained in Industrial Group Cross Examination Exhibit IG-CX-5 from IGCC-11.

Q. What is shown in Exhibit LA-16?

A. Exhibit LA-16 contains a copy of Petitioner's response to CAC 2.1 regarding the operation of the Edwardsport IGCC relevant to the IGCC-12 and 13 review periods.

Q. What is shown in Exhibit LA-17?

A. Exhibit LA-17 contains a copy of Petitioner's CONFIDENTIAL responses to DEI-IG 4.24 and DEI-IG 6.1d, which show Edwardsport net generation for the period June 2013 through March 31, 2014.[2]

Q. What is shown in Exhibit LA-18?

A. Exhibit LA-18 contains a copy of the April 24, 2012 Order in Case No. 2009-UA-01 (Final Order on Remand), where the Mississippi Public Service Commission articulated its conceptual framework in the context of the Kemper IGCC that is being constructed by Mississippi Power Company to protect Mississippi ratepayers from potential poor operational performance. The Mississippi Public Service Commission's Final Order on Remand includes the following conceptual framework for protecting ratepayers from poor operational performance of the Kemper IGCC that is being constructed by Mississippi Power Company:

[2] Counsel for Petitioner confirmed with Joint Intervenor counsel that Edwardsport net generation on a monthly or longer period basis does not need to be treated as being confidential. Similar monthly net generation information is available from the Energy Information Administration (EIA) on a public basis.

> "The operational cost and performance parameters assure that ratepayers will not pay for an underperforming asset." ¶ 10

> "Put simply, if Kemper doesn't perform as advertised then the ratepayers will not pay for it." ¶179

Q. What is shown in Exhibit LA-19?

A. Exhibit LA-19 contains a copy of Petitioner's response and September 13, 2014 supplemental response to CAC 10.2 and Petitioner's response to CAC 10.6.

Q. What is shown in Exhibit LA-20?

A. Exhibit LA-20 contains a copy of Petitioner's December 5, 2014 Supplemental Response to DEI-IG 1.8 regarding the meaning of certain terms in the Section 2 and related attachments of the IGCC-4S1 Settlement.

Q. What is shown in Exhibit LA-21?

A. Exhibit LA-21 contains a copy of Petitioner's Responses to DEI-IG 4.8, DEI-IG 4.9, and DEI-IG 4.10.

Q. What is shown in Exhibit LA-22?

A. Exhibit LA-22 contains a copy of Petitioner's Response to DEI-IG 4.14.

Q. What is shown in Exhibit LA-23?

A. Exhibit LA-23 contains a copy of Petitioner's Response to DEI-IG 4.31.

Q. What is shown in Exhibit LA-24?

A. Exhibit LA-24 contains a copy of Petitioner's October 13, 2014 Supplemental Response to DEI-IG 3.6.

Q. What is shown in Exhibit LA-25?

A. Exhibit LA-25 contains a copy of Petitioner's CONFIDENTIAL Response to CAC 6.38.

Q. What is shown in Exhibit LA-26?

A. Exhibit LA-26 contains a copy of Petitioner's Responses to DEI-IG 6.4 and DEI-IG 6.5.

Q. What is shown in Exhibit LA-27?

A. Exhibit LA-27 contains a Copy of Company witness Diana Douglas's Workpaper 12 from IGCC-12.

Q. What is shown in Exhibit LA-28?

A. Exhibit LA-28 contains a copy of Petitioner's Response to CAC 10.16 and Attachment 10.16-A.

Q. What is shown in Exhibit LA-29?

A. Exhibit LA-29 contains a copy of Petitioner's Responses to CAC 18.28 and CAC 18.29.

Q. What is shown in Exhibit LA-30?

A. Exhibit LA-30 contains a copy of Petitioner's Responses to CAC 22.3 and Confidential Attachment 22.3-A.

Q. What is shown in Exhibit LA-31?

A. Exhibit LA-31 contains a copy of Petitioner's Responses to CAC 22.4 and Confidential Attachment 22.4-A.

Q. What is shown in Exhibit LA-32?

A. Exhibit LA-32 contains a copy of Petitioner's Responses to CAC 25.2 (not including bulk attachment).

Q. What is shown in Exhibit LA-33?

A. Exhibit LA-33 contains a copy of Petitioner's Responses to CAC 18.8 through CAC 18.27.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. What is the intended purpose and scope of your testimony regarding the matters before the Commission in this proceeding?

A. The general purpose and scope of my testimony is to assist the Joint Intervenors by providing consulting and expert witness services related to accounting, tax and ratemaking issues associated with the Edwardsport IGCC raised by the Company's prefiled direct testimony in this proceeding. More specifically, the purpose of my testimony is to explain the reasons that, in my professional opinion:

1. The evidence available to Joint Intervenors does not support the Company's unilateral declaration on June 7, 2013, that Edwardsport was "in service" and ready for commercial operation as an "integrated gasification combined cycle" base load electric generating facility with a rated capacity of 618 MW for the months of October through May and 586 MW for the months of June through September;

2. The evidence available to Joint Intervenors does not support the proposition that Edwardsport was "in service" and ready for commercial operation at any time from June 7, 2013 through March 31, 2014 as an "integrated gasification combined cycle" base load electric generating facility with a rated capacity of 618 MW for the months of October through May and 586 MW for the months of June through September;

3. The Commission should disallow a substantial part of the actual costs of Edwardsport claimed by the Company in this proceeding and refund a substantial part of the plant's costs previously projected by the Company in prior proceedings and previously collected in customer rates for the period of April 1, 2013 through March 31, 2014;

4. The Commission should establish an operating expense cost cap and performance standards for the future commercial operation of Edwardsport to protect

Indiana ratepayers from a continuation of the poor performance and unreasonably high costs the plant exhibited from June 2013 through March 2014; and

5. The proposal included in the Company's testimony in IGCC-11 and reflected in the exhibits of its witness Douglas in this consolidated proceeding to amortize over three years the refund or credit to customers of the "Deferred Tax Incentive" (also sometimes called the "Cost Control Incentive") collected between August of 2010 and December 2012, without interest, should be rejected in favor of an immediate refund or credit, with interest at the statutory rate of eight percent.

III. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations on the topics you address in detail later in your testimony.

A. My conclusions and recommendations may be summarized as follows:

(1) I recommend that the Commission should deny most of the Company's request for relief in this Cause on the grounds that:

A. The Company prematurely declared Edwardsport to be "in service" (i.e., in or ready for commercial operation) as of June 7, 2013, under the applicable legal and accounting standards.

B. Edwardsport was not "in service" (i.e., in or ready for commercial operation) at any time from June 7, 2013, through March 31, 2014 under the applicable legal and accounting standards.

C. Even assuming that Edwardsport was in or ready for "commercial operation" as of a date between June 7, 2013, and March 31, 2014, a substantial part of the revenue requirement of approximately $184 million claimed by the Company for retail ratemaking purposes for the six month period in IGCC-12 and the requirement of approximately $187 million claimed by the Company for the six-month IGCC-13 period are not "reasonable and necessary" as required by law because they are excessive in relation to the value of the generation produced by Edwardsport during that period.

D. Even assuming that Edwardsport was in or ready for "commercial operation" as of a date between June 7, 2013 and March 31, 2014, the

Company has improperly classified certain costs as current operating and maintenance (O&M) expenses which it should have capitalized as "construction costs" subject to the "hard cap" approved in Cause No. 43114-IGCC-4S1

(2) For reasons described in my Direct Testimony in IGCC-11, and briefly reiterated herein concerning Petitioner's holding of ratepayer monies previously collected for the "Deferred Tax (Cost Control) Incentive" that the Commission has ordered be refunded, I recommend that:

(A) The Commission should direct the Company to accrue simple interest at the statutory rate of eight percent (8%) per annum from the date of collection on the $30,731,789 Cost Control Incentive (aka Deferred Tax Incentive) revenues collected from approximately July 29, 2010 through the next applicable billing cycle in which the Commission ordered refund can be fully returned to customers.

(B) The Commission should direct the Company to credit the $30,731,789 in Cost Control Incentive (aka Deferred Tax Incentive) revenues collected against the revenue requirement in the IGCC-11 proceeding,[3] rather than allowing the Company to continue to hold onto this ratepayer money for three more years as its witness Douglas has proposed in her Supplemental Direct Testimony in IGCC-11 and in her Direct Testimony here in IGCC-12 and -13. This could be accomplished by the Commission in its pending IGCC-11 Order by therein ordering the Company to replace the $5,121,965 amount for the Petitioner-proposed one-sixth amortization of the Cost Control Incentive on Petitioner's Exhibit D-5, page 4 of 9, line 14, with the full $30,731,789 Cost Control Incentive amount plus simple interest at the statutory rate of 8% for the period during with Petitioner has held such ratepayer money.

(C) In conjunction with that IGCC-11 adjustment, the amortization amounts of $5,121,965 in IGCC-12 and $5,121,965 in IGCC-13 should be eliminated as adjustments to the revenue requirements proposed in DEI witness Douglas' exhibits prefiled in each of those dockets.

[3] Concurrent with the filing of their IGCC-11 testimony, Joint Intervenors also filed their motion requesting the Commission to set aside, in an interest-bearing account, a part of the refund or credit amount that the Commission determines to be due to DEI customers, in order to pay from this "common fund" both the interim and ultimate amounts of attorney's fees and litigation expenses, which the Commission determines to be due to Joint Intervenors (as well as the other non-Duke parties) and their counsel. My recommended refund or credit in IGCC-11 would be reduced by the amount of this set aside.

Q. Have you prepared an illustrative estimate of the cost per kWh to ratepayers from the Edwardsport IGCC through March 31, 2014 based on the revenues collected by Petitioner and the net generation of the Edwardsport IGCC through that date?

A. Yes. As shown on Exhibit LA-12, the estimated cost to ratepayers of the Edwardsport IGCC based on approximately $688 million of revenue and net generation from June 2013 through March 2014 is $567.81 per MWh, or $0.57 per kWh.

Q. Have you prepared an illustrative estimate of the amount of IGCC-12/13 revenue requirement that would be disallowed if the Commission determines that the Edwardsport IGCC was not in commercial operation during the IGCC-12/13 review period?

A. Yes. Exhibit LA-13 presents a calculation showing an Estimated IGCC-12/13 Revenue Requirement Adjustment for Edwardsport IGCC Not Being in Commercial Operation During the IGCC-12/13 Review Period. This Exhibit estimates the adjustment would be a reduction to Petitioner's IGCC-12/13 requested revenue requirement of approximately $141.5 million, based on removing Petitioner's requested revenue requirement production plant depreciation expense and operating expenses. If the Edwardsport IGCC is not in commercial operation during the IGCC-12/13 review period, there would no depreciation expense recorded on the production plant for this period. Additionally, the large amounts of O&M expenses that are claimed by Petitioner would be treated as construction costs, and would thus be subject to the Hard Cost Cap. This calculation does not incorporate additional return on CWIP from additional post June 7, 2013 AFUDC accruals, which Petitioner may claim that it is entitled to under the terms of the Settlement Agreement. The impact of potential additional AFUDC has not been quantified, but if allowed by the Commission as an offset, it would lower the amount of the $141.5 million cost disallowance related to the Edwardsport IGCC not being in commercial operation during the combined IGCC 12/13 review periods. Joint Intervenors presented arguments against additional Indiana ratepayer responsibility for additional "costs of delay" in IGCC-9, 10 and 11, which would include additional post-June 7, 2013 AFUDC accruals.

Q. Have you prepared an illustrative estimate of the a performance adjustment for costs claimed by Petitioner for the Edwardsport IGCC during the IGCC-12/13 review period, based on Petitioner's presumption that the plant was in-service from June 7, 2013 through March 31, 2014?

A. Yes. While Joint Intervenors believe there is strong evidence in this cause showing that the Edwardsport IGCC was not in commercial operation for its intended purpose during the IGCC-12/13 review period, an illustrative calculation has been prepared, as shown on Exhibit LA-14, to reflect an adjustment to Petitioner's requested costs, based on the very poor operating performance of the plant during this period, as detailed in the testimony of Joint Intervenors witness Schlissel. As shown on Exhibit LA-14, removing 55 percent (the performance adjustment) of Petitioner's requested IGCC-12/13 revenue requirement amounts for return, depreciation, and property taxes results in a reduction of approximately $161.2 million.

Q. Have you prepared an illustrative estimate of the amount of excessive operating costs requested by Petitioner for the Edwardsport IGCC during the IGCC-12/13 review period?

A. Yes. LA-15 presents an Estimated Adjustment for Excessive Operating Expenses During the IGCC-12/13 Review Period. This adjustment is based on a comparison of Petitioner's reported actual operating expenses during the portion of the IGCC-12/13 review period when Petitioner has claimed that the Edwardsport IGCC was in commercial operation versus the previous presentation of estimated operating expenses for the first year of plant operation that is contained in Industrial Group Cross

Examination Exhibit IG-CX-5 from IGCC-11. This adjustment reduces Petitioner's requested revenue requirement for IGCC-12/13 by approximately $18.5 million.

IV. "COMMERCIAL OPERATION" OF THE EDWARDSPORT IGCC DID NOT OCCUR DURING THE COMBINED IGCC-12 AND 13 REVIEW PERIODS

Q. What period of commercial operation has Petitioner claimed for the Edwardsport IGCC generating plant?

A. Petitioner has claimed an in-service date for Edwardsport IGCC generating plant of June 7, 2013, thus suggesting that the plant has been in commercial operation from June 7, 2013 through September 30, 2013, the end of the IGCC-12 period, and throughout the IGCC-13 period of October 2013 through March 2014 and beyond.

Q. How does the "in service" date issue affect costs for the Edwardsport IGCC that are being charged to Indiana ratepayers?

A. DEI declared Edwardsport to be “in service” on June 7, 2013. This was during the IGCC-12 review period, which extends from April through September 2013. Thus, IGCC-12 includes both two-plus months (April 1 through June 6, 2013) of the Project’s construction and startup phase and the three-plus months (June 7 through September 30, 2013) of its operational phase. By its Order dated May 23, 2014, the Commission combined the IGCC-12 and 13 review periods, which extended the period for review in the current proceeding to include the IGCC-13 period of October 2013 through March 2014.

Q. Is another witness for Joint Intervenors presenting testimony on the actual operation of the Edwardsport IGCC since June 7, 2013?

A. Yes. Joint Intervenors witness David Schlissel's testimony includes details about his review of the actual operation of the Edwardsport IGCC from June 7, 2013 through March 31, 2014, the end of the combined IGCC-12 and 13 review periods.

Q. What accounting guidance did DEI state that it would be following for determining whether and when the Edwardsport IGCC was in-service for its intended use?

A. DEI's response to CAC 4.6 in IGCC-8 stated as follows:

> The Company will be following the FERC's guidance in Electric Plant Instructions 3 and 9 and in Accounting Release AR-5, "Capitalization of Allowance for Funds Used During Construction" as well as the FASB's guidance in Accounting Standards Codification section 360-10-30-1, "Property, Plant, and Equipment – Overall – Initial Measurement – General – Historical Cost Including Interest."

Q. What does the Accounting Standards Codification section 360-10-30-1 state with respect to whether an asset is in service?

A. ASC section 360-10-30-1, Paragraph 835-20-05-1, states that the historical cost of acquiring an asset includes the costs necessarily incurred **to bring it to the condition and location necessary for its intended use**. As indicated in that paragraph, if an asset requires a period of time in which to carry out the activities necessary to bring it to that condition of intended use and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset.

Q. What is the intended use of the Edwardsport IGCC?

A. The intended use of the Edwardsport IGCC was as an integrated gasification combined cycle generating facility able to be dispatched economically by MISO and able to produce electricity using gasified coal as its fuel stock for commercial operation as a base load unit with a rated capacity of 618 MW for the months of October through May and 586 MW for the months of June through September.

Q. What guidance is provided in the FERC's Electric Plant Instructions 3 and 9?

A. These FERC Electric Plant Instructions primarily describe how to account for a plant once the construction and testing phase has been completed and the plant has been placed into service for its intended use. These instructions are not particularly illuminating about evaluating whether a plant is in service for its intended use. Determining whether the plant is in service is thus of necessity a fact-based determination that considers a variety of factors, such as the intended use and the degree to which that use is being met.

Q. What is stated in Uniform System of Accounts Electric and Gas Plant Instruction 9(E)?

A. Uniform System of Accounts Electric and Gas Plant Instruction 9(E) states that

> The cost of efficiency or other tests made subsequent to the date equipment becomes available for service shall be charged to the appropriate expense accounts, except that tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase may be charged to the appropriate electric plant account.

Q. Does the Uniform System of Accounts, Electric and Gas Plant Instruction 9(E) provide a loophole where a plant can be operated only for a few hours and declared to be "in service" before testing is complete, before the plant itself is substantially complete, and when the plant is not operating at levels consistent with its intended use for commercial operation?

A. No. Although DEI appears to be relying upon Plant Instruction 9(E) as if it has created a loophole in the in-service criteria, by inferring that some types of testing can occur after commercial operation has been achieved, that type of strained interpretation is contrary to the basic guidance, and to DEI's other own-stated criteria for the plant to be in service and functioning for its intended purpose. Uniform System of Accounts Electric and Gas Plant Instruction 9(E) thus should be viewed as providing accounting guidance for how to account for subsequent testing cost. It provides some accounting guidance for different types of testing costs. In particular, it provides that costs for tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase, should be charged to the appropriate electric plant account.

Q. Was some of the Edwardsport testing for tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, and thus per this FERC guidance, should be charged to the appropriate electric plant account?

A. Yes. For example, the cost of NPI Testing through September 2013, as well as the Preliminary Performance Test, the Final Performance Test and the Operability (Ramping) Demonstration, per this FERC guidance, all should be charged to the relevant plant account, i.e., charged back to Construction Costs subject to the Hard Cap, even if commercial operation had been achieved before those tests. Here, of course, other factors demonstrate that Edwardsport was not in "commercial operation" during the IGCC-12/13 combined review periods.

Q. When a plant is placed in service, are there related notification requirements?

A. Yes. For a major project, like the Edwardsport IGCC, notification to FERC and to the state regulatory commission is required. For example, DEI's response to CAC 4.7 in IGCC-8 stated as follows:

> Duke Energy Indiana states as follows: Upon completion of the test period and declaration of the plant as in-service, the Company will be notifying FERC in accordance with Electric Plant Instruction 9.D, which is required due to the testing period extending beyond a period of 90 days. In addition, the Company will notify the IURC when the IGCC Project has been declared "in service" for accounting and ratemaking purposes as part of the Company's ongoing review filings in the IGCC Rider proceedings.

Q. Did DEI notify the Commission and FERC of DEI's declaration of the Edwardsport being "in service" as of June 7, 2013?

A. Yes, it appears DEI notified FERC and the IURC of its declaration of the Edwardsport being "in service" as of June 7, 2013.

Q. Did DEI also notify the Midcontinent Independent System Operator ("MISO") that Edwardsport was being placed "in service" as of June 7, 2013?

A. Yes, DEI also notified MISO that the Edwardsport IGCC was being placed "in service" as of June 7, 2013.

Q. Has DEI represented in its legal pleadings that "there is a genuine issue of material fact regarding DEI's in-service declaration"?

A. Yes. DEI has made this representation, including in its April 7, 2014 *Response to Joint Intervenors' Motion for Partial Summary Judgment.*

Q. What did DEI's response to CAC 4.4 in IGCC-8 state concerning how DEI would put the Edwardsport IGCC plant into service only after testing was complete and the plant was ready for its intended use as an integrated gasification combined cycle generating facility?

A. DEI's response to CAC 4.4 in IGCC-8 stated as follows:

> The “initial start-up and generation of test power for sale” occurs while the plant is still in test phase, which is earlier than when the plant will be declared as in-service for accounting and ratemaking purposes. The plant will be declared in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.

Q. During the IGCC-12 and 13 periods was the Edwardsport IGCC still in test phase?

A. Yes, it was. The testing that was conducted at the Edwardsport IGCC during the IGCC-12 and 13 periods is addressed in additional detail in Joint Intervenors witness Schlissel's testimony.

Q. What did DEI's response to CAC 4.5 in IGCC-8 state concerning when the Edwardsport IGCC would be considered to be in service and ready for its intended use?

A. DEI's response to CAC 4.5 in IGCC-8 stated as follows:

> The plant will be declared in-service for accounting and ratemaking purposes once testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.

Q. During the IGCC-12 and 13 periods, was the Edwardsport IGCC operating for its intended use?

A. No, it was not. During this period, the plant was not economically dispatched by MISO and was not operated or ready for operation for a sustained period as an **integrated** gasification combined cycle base load generating facility at a capacity of 586 MW for the months of June through September 2013 or at 618 MW for October 2013 through the remainder of the IGCC-13 review period.

Q. What types of testing for the Edwardsport IGCC had DEI failed to complete by March 31, 2014, the end of the combined IGCC-12 and 13 review periods?

A. As of March 31, 2014, several types of testing had not yet been completed. Mr. Schlissel discusses the testing that DEI had not yet completed of the Edwardsport IGCC in additional detail in his testimony. Some illustrative examples of testing that had not been completed as of March 31, 2014 include the following:

- The operability demonstration tests were not completed by March 31, 2014 but were scheduled by DEI for August 2014.[4]
- The preliminary performance test was not completed by March 31, 2014 but was completed after March 31, 2014, on April 2, 2014.[5]
- The final contractually-required GE performance testing was not completed by March 31, 2014 but was completed after March 31, 2014, on May 15-16, 2014.[6]

Since this testing was not completed by March 31, 2014 (the end of the IGCC-13 review period), it follows, and was affirmed in DEI's response to DEI-IGCC 4.14, that such testing likewise had not been completed by September 30, 2013, the end of the IGCC-12 review period.

Q. Has DEI met its own criteria for declaring the Edwardsport IGCC plant to be in commercial operation on June 7, 2013?

---

[4] See, e.g., DEI's response to DEI-IG-4.8.
[5] See, e.g., DEI's response to DEI-IG-4.9.
[6] See, e.g., DEI's response to DEI-IG-4.10.

A. No. The "initial start-up and generation of test power for sale" has been occurring at least through March 2014, the end of the IGCC 13 review period. Through March 2014 the Edwardsport IGCC has been undergoing substantial testing, has not been economically dispatched by MISO, and has not functioned at a level commensurate with commercial operation.

Q. Are the concepts of substantial completion and final completion typically associated with the date of commercial operation?

A. Yes, it is normal for those dates to be identical or closely aligned for most types of utility plant under construction that becomes commercially operational. DEI has attempted to separate and divorce the concepts of substantial completion and commercial operation with respect to the Edwardsport IGCC; however, that appears to be unusual and commonly those dates are closely aligned.

Q. Had DEI accomplished final or substantial completion of the Edwardsport IGCC at the time it filed its direct testimony in IGCC 13?

A. No. DEI's response to DEI-IG 4.31 contained the follow admissions, based on DEI's understanding of the 2007 Duke Energy/GE Contract:

> a. Please admit that Duke had not accomplished final completion of the Plant as of the time Mr. Stultz filed his testimony in IGCC 13. If Duke denies this, when was final completion accomplished? Explain any denial.
>
> b. Please admit that Duke had not accomplished substantial completion of the Plant as of the time Mr. Stultz filed his testimony in IGCC 13. If Duke denies this, when was final completion accomplished? Explain any denial.
>
> c. Please admit that over a year after declaring the Plant to be in-service, it still had not reached final or substantial completion. Explain any denial.
>
> RESPONSE:
>
> a. Admit.
>
> b. Admit.
>
> c. Admit.

It is thus clear that the Edwardsport IGCC had not achieved substantial completion during the combined IGCC-12 and 13 review periods, by Petitioner's own admission.

Q. Is the Joint Intervenors' analysis that shows that the Edwardsport IGCC was not in commercial operation during the IGCC-12 and 13 review periods dependent upon equating "commercial operation" with "substantial completion" or "final completion" as those terms are defined in the Duke-GE Contract and the IGCC-4S1 Settlement?

A. No. It is based on an analysis of "in or ready for commercial operation" applying the facts concerning how the Edwardsport IGCC continued to undergo substantial testing during the IGCC-12 and 13 review periods, the facts concerning the lack of economic dispatch by MISO of the plant during this period, the failure of the plant to run at capacity for a sustained period, and the overall poor operating performance of the plant during this period. Section 2 of the IGCC-4S1 Settlement Agreement, starting with the first part of the definition of "In Service Operation Date" included in subpart 2F: ""In-Service Operational Date" means the first date by which the Project has both (1) been declared in-service in accordance with FERC guidelines as the earlier of the date the asset is placed in operation or is ready for service." As explained in my testimony and in the testimony of Joint Intervenors witness Schlissel, the FERC guidelines for commercial operation have been applied to the technical and operational facts developed in Mr. Schlissel's testimony to demonstrate that the Edwardsport IGCC was <u>not</u> in or ready for commercial operation during the IGCC-12 and 13 review periods.

Q. Has the Edwardsport IGCC plant been economically dispatched by MISO during the IGCC-12 and 13 review periods?

A. No. During the period from June 7, 2013 through March 31, 2014, the Edwardsport IGCC plant has been designated as must run for testing, and has not been economically dispatched by MISO. The intended use of the Edwardsport IGCC was as an integrated gasification combined cycle plant to operate under economic dispatch by MISO. The fact that the Edwardsport IGCC was not operated on MISO economic dispatch during the entire IGCC-12/13 period, as further documented in the testimony of Joint Intervenors witness Schlissel, is another key fact showing that the plant was not in commercial operation during the IGCC-12/13 review period.

Q. Has DEI recently provided a table showing for each month from June 2013 to the present, the percentage of time that DEI dispatch personnel offered Edwardsport to MISO on a "must run" basis?

A. Yes. DEI's October 13, 2014 supplemental response to DEI-IG 3.6 included the following table that shows the percent of time, by month, that Edwardsport was offered with a Commit Status of Must Run in the MISO Day-Ahead Market:

Month	
Jun-13	29%
Jul-13	71%
Aug-13	100%
Sep-13	73%
Oct-13	77%
Nov-13	43%
Dec-13	87%
Jan-14	76%
Feb-14	20%
Mar-14	81%
Apr-14	93%
May-14	97%
Jun-14	97%
Jul-14	94%
Aug-14	100%

Q. Where the above table shows a percentage of less than 100 percent, does that mean that the Edwardsport IGCC was offered by DEI to MISO on an economic basis in the Day-Ahead Market for the rest of the time in that month?

A. No. Where the above table shows a percentage of less than 100 percent, that does not mean that the Edwardsport IGCC was offered by DEI to MISO on an economic basis in the Day-Ahead Market for the rest of the time in that month. The lower percentages in the table appear to represent portions of time in each month (at least for the IGCC-12 and 13 review period months of June 2013 through March 2014) when the Edwardsport IGCC was shut down and was not operating and thus was not offered at all to MISO. Joint Intervenors witness Schlissel's Direct Testimony in this Cause presents several figures and tables showing how the actual Edwardsport IGCC plant operation during the combined IGCC-12 and 13 review periods has compared poorly with various operating and performance benchmarks.

Q. What is the intended use of the Edwardsport IGCC?

A. The intended use of the Edwardsport IGCC is to generate power using gasified coal at levels and costs consistent with commercial operation, as a baseload unit, i.e., to have the plant dispatched economically by MISO with sufficient regularity and to produce electricity at sufficient levels of generation to achieve a capacity factor at or above 72% on syngas during its initial year to 15 months of operation.[7]

Q. Has that occurred during the IGCC-12 and 13 review periods?

A. No. This intended use of the Edwardsport IGCC to generate power using gasified coal at levels consistent with commercial operation as a baseload unit has simply not

[7] See also the Direct Testimony of Joint Intervenors witness Schlissel which contains a detailed discussion of the plant's intended operation and its very poor actual operating performance during the IGCC-12/13 review periods.

occurred during the IGCC-12 and 13 review periods, i.e., in the 12 month period ending March 31, 2014. For example, the Company's CONFIDENTIAL Attachment to CAC 6.38 shows that [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Thus, rather than being dispatched into MISO, the plant was shut down and was not generating electricity. Joint Intervenor witness Schlissel's Direct Testimony in this Cause contains additional details of the "must run" designation of the Edwardsport IGCC throughout the IGCC-12/13 review periods, and of the very poor overall operating performance of the Edwardsport IGCC through the IGCC-12/13 review periods.

Q. Has DEI explained how it offered the Edwardsport plant to MISO when testing needed to be done at Edwardsport?

A. Yes. DEI witness Swez included descriptions of this in recent FAC proceedings.[8] Additionally, DEI's response to DEI-IG 6.4(e) stated that to the extent there was testing that needed to be done at Edwardsport, the plant would be offered to MISO as

---

[8] See, e.g., Cause No. 38707 FAC 101, Hearing Transcript, p. 8, lines 5-8 ("If testing of a unit is necessary, the generation owner would designate the unit as must-run; right?
A--That's correct."); p. 11, lines 8-12 ("Q Okay. We're going to get into many of those points you just made in a little bit, but is it must-run when it's testing?
A When a unit is testing, it is typically must-run, yes."); and p. 14, lines 16-23 ("Has Edwardsport always been offered with a commitment status of must-run with a minimum and maximum output dictated by the specific schedule and unit availability up to the current outage?
A During times when syngas was expected to be on line or the unit was on line on natural gas and testing, yes, that's correct."); and Cause No. 38707 FAC 101, Petitioner's Exhibit 6, p. 5, lines 4-6 ("If testing of a unit is necessary, the generation owner would designate the unit as "must run," usually designating a specific hourly output for the generating unit." and p. 21, lines 1-4 ("During the early operations of the plant, the station is being offered with a commitment status of must-run with the minimum and maximum output dictated by the specific schedule and unit availability. During these times, the output of the station is coded as testing.")

"must run."[9] Joint Intervenors witness Schlissel's Direct Testimony in this Cause contains additional details of the "must run" designation of the Edwardsport IGCC through the IGCC-12/13 review periods.

Q. For regulatory purposes, should the Edwardsport IGCC plant be treated as if it were in commercial operation for the period from June 7, 2013 through March 31, 2014?

A. No, it should not. As Mr. Schlissel and I have explained, the intended use of the Edwardsport IGCC is to generate power using gasified coal at levels and costs consistent with commercial operation as a baseload unit. That intended use has not occurred during the IGCC-12 and 13 review periods, i.e., in the 12 month period ending March 31, 2014. Moreover, the evidence shows that during this period the Edwardsport IGCC performed very poorly (i.e. significantly below a level consistent with commercial operation on gasified coal) and continued to undergo substantial testing, which was not completed by March 31, 2014, which further indicates that the plant should not be considered to be in commercial operation during the IGCC-12 and 13 review periods.

Q. What would the regulatory significance be if the Commission determined that the Edwardsport IGCC was not in commercial operation during the IGCC 12 and 13 review periods?

A. If the Commission determined that the Edwardsport IGCC was not in commercial operation during the IGCC-12 and 13 review periods, the plant would be considered to still be under construction for regulatory purposes. The accounting implications of the plant still being under testing and construction would be that (1) depreciation would not be recognized; (2) costs continuing to be incurred for pre-commercial

[9] Also, see response to data request DEI-IG 6.5(c).

operation testing and construction would be capitalized as construction costs rather than expensed as operating and maintenance expenses. To the extent that the construction costs are exceeding the "hard cost cap" that was contained in the Settlement Agreement among various parties, which was approved by the Commission in IGCC-4S1, this would shift responsibility for such costs during the IGCC-12 and 13 review periods from being the responsibility of Indiana Retail jurisdictional ratepayers to DEI's shareholders. Additionally, accruals of AFUDC would continue. Whether further accruals of AFUDC or a continuing cash return on CWIP under Indiana Code Section 8-1-8.8 (like what happened in April, May and the first week of June 2013) beyond June 7, 2013 represent a cost of delay that should be borne by shareholders or Indiana retail jurisdictional ratepayers would thus be another issue that would need to be addressed.

Q. What was provided for in Section 3 of the Settlement Agreement that was reached by DEI and other parties (not including Joint Intervenors) in IGCC-4S1?

A. Section 3 of the Settlement Agreement that was reached by DEI and other parties (not including Joint Intervenors) in IGCC-4S1 provided as follows:

> The Settling Parties agree that in IGCC-9 (to be filed in approximately May 2012), Duke Energy Indiana's proposed tariffs will not include costs of post-in-service Project depreciation or O&M costs (or property taxes) for inclusion in the IGCC-9 Rider (other than operating costs for items that have been included in previous Rider filings). Thus, the IGCC-9 filing will reflect financing costs (CWIP), but no post-in-service depreciation or O&M costs (or property taxes). Rather, in IGCC-l0 (to be filed in approximately November 2012), Duke Energy Indiana will begin recovering post-in-service Project depreciation and O&M costs (and property tax expenses) on a projected basis for a six-month period. Duke Energy Indiana will defer the actual depreciation and O&M costs (and property tax expenses) incurred for all months from the In-Service Operational Date until the effective date of IGCC-10 rates. At the time of the next IGCC Rider filing (or general base rate case filing) after the filing of IGCC-10, Duke Energy Indiana will recover the deferred amount

(without carrying costs) over a three-year period either through the IGCC Rider or through inclusion in base retail electric rates.

Q. Should O&M expenses or depreciation expense be charged to Indiana ratepayers before the Edwardsport IGCC is in commercial operation?

A. No. For the period before the Edwardsport IGCC is in commercial operation, no O&M expenses and no depreciation should be charged to Indiana ratepayers. Because the Edwardsport IGCC was not in commercial operation during the IGCC-12 or 13 review periods, all O&M and depreciation expenses charged to ratepayers for this period should be identified in a compliance filing by DEI and refunded to ratepayers.

Q. Should O&M expenses or depreciation expense be charged to Indiana ratepayers after the Edwardsport IGCC is in commercial operation?

A. For the period after the Edwardsport IGCC is in commercial operation (which was not during the IGCC-12 or 13 review periods) O&M expenses and depreciation should be recorded and recovered; however, the level of such expenses should not represent a "blank check" from Indiana ratepayers to DEI and should be limited to be commensurate with the actual operation and performance of the plant.

Q. What conclusions can be drawn from the details about the actual operation of the Edwardsport IGCC since June 7, 2013?

A. A conclusion can be drawn that the Edwardsport IGCC has not operated with any consistency at a commercial operating level even generally, let alone using gasified coal as a fuel source, during the combined IGCC-12 and 13 review periods, i.e., through March 31, 2014, and possibly beyond. As explained by Mr. Schlissel, the Edwardsport IGCC, as of March 31, 2014, had not yet completed the testing required for "substantial completion"[10] or to demonstrated that it could operate consistently at

[10] Unlike other electric generating plant construction projects, Petitioner had attempted to differentiate between "substantial completion" of the Edwardsport IGCC and the plant's "in-service" date for commercial operation.

a commercial operating level using gasified coal as a fuel source to function as intended as an **integrated** gasification combined cycle (IGCC) baseload generating facility for the future, i.e., the subsequent period continuing after the end of the combined IGCC-12 and 13 review periods, i.e., through March 31, 2014, and possibly beyond.

As the evidence shows, from the Company's declared "in-service" date of June 7, 2013 through March 31, 2014, the end of the combined IGCC-12 and 13 review periods, the Edwardsport IGCC did not run for a single hour under MISO economic dispatch. Running under MISO economic dispatch using gasified coal as the fuel source would be consistent with commercial operation of the Edwardsport IGCC. During the combined IGCC-12 and 13 review period, this did not occur at all. Rather, the Edwardsport IGCC operated exclusively as "must run for testing" for MISO dispatch purposes.

Q. Is the lack of consistent operation from the Edwardsport IGCC at a commercial level during the combined IGCC-12 and 13 review period (and beyond) harming Indiana ratepayers?

A. Yes. The lack of consistent operation and lack of MISO economic dispatch of the Edwardsport IGCC at a commercial level during the combined IGCC-12 and 13 review periods (and beyond) is harming Indiana ratepayers in numerous respects. Indiana ratepayers are being asked to pay for the very high cost of a first-of-a-kind integrated gasification combined cycle plant without receiving a commercial level of performance from this plant. As described in Mr. Schlissel's testimony, the periods of actual operation using gasified coal as the fuel source for the Edwardsport IGCC have been intermittent in occurrence and far below expectations in performance. The operation of the Edwardsport IGCC with gasified coal as the fuel source has not achieved a sustained level of commercial operation during the combined IGCC-12 and 13 review periods. Additionally, as described by Petitioner and the OUCC in Petitioner's recent fuel adjustment clause ("FAC") cases[11], Edwardsport generation using gasified coal has been treated as "test energy." Edwardsport generation using gasified coal has been designated for "must run" dispatch by the Midcontinent Independent System Operator ("MISO") for this testing, which was continuing through March 31, 2014, the end of the combined ICGG-12 and 13 review periods, and beyond. There has been no MISO economic dispatch of the Edwardsport IGCC during the combined IGCC-12 and 13 periods using gasified coal. Moreover, even when the plant was using natural gas for generation during the combined IGCC-12 and 13 periods, there has been no MISO economic dispatch of the Edwardsport IGCC. For Edwardsport generation using gasified coal, the analysis conducted through the IGCC-12 and 13 periods strongly shows that the plant during these periods was still in an extensive "testing" stage and remained in a "testing" stage from the Company's declared "in-service" date of June 7, 2013, through the entire combined IGCC-12 and 13 review period, i.e., through March 31, 2014. Simply put, as explained by Mr. Schlissel, the plant has not been able to operate at commercial levels reliably or economically using gasified coal as the fuel source during the IGCC-12 and 13 review periods.

Q. What did the prefiled testimony of Petitioner's witness Swez in Cause No. 38707-FAC-99, state concerning Edwardsport testing and MISO dispatch of the Edwardsport IGCC?

[11] See, e.g., FAC-98 and FAC-99.

A. Concerning testing and MISO dispatch of the Edwardsport IGCC, the prefiled testimony in Cause No. 38707-FAC-99, of DEI witness Swez stated in pertinent part that:

> During times when Edwardsport IGCC is performing testing, tuning, and optimization, the station is offered [to MlSO] with a commitment status of must run with the minimum and maximum output dictated by the specific schedule and unit availability. During these situations, the output of the station is coded as testing. The Company's offer to MISO essentially results with the MlSO dispatch following the output of the units during this time rather than MlSO determining the level of output the unit. However, during situations when syngas is not available, testing, tuning, and optimization is not required with natural gas operation, and the station is available on natural gas operation, the unit is offered to MISO as an economic resource and can be committed and dispatched at MlSO's discretion. During these situations, the output of the station is not coded as testing.

The Direct Testimony of Joint Intervenors witness Schlissel discusses additional information concerning the "must run" status of the Edwardsport IGCC during the IGCC-12/13 review periods. As described by Mr. Schlissel and below, the "testing" of Edwardsport has continued through and beyond March 31, 2014, the end of the combined IGCC 12/13 review periods.

Q. Did the "testing" of the Edwardsport IGCC continue through at least March 31, 2014, the end of the combined IGCC-12 and 13 review period?

A. Yes, it did. For example, Duke's Supplemental CONFIDENTIAL Response CAC 10.25(d), (e) provided on October 3, 2014 stated that [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] Duke's Supplemental Response CAC 5.1, provided on October 3, 2014, stated that, during June 2013 through February 2014, energy generated by Edwardsport IGCC using gasified coal as the fuel source was coded internally as "test." Duke's Supplemental Response CAC 5.2, provided on October 3, 2014, stated that: "From June 7, 2013 through February 28, 2014 when the gasifiers were running and energy was being produced by the facility, Edwardsport was offered with a commitment status of must-run with the minimum and maximum output dictated by the specific schedule and unit availability."

Also, in Cause No. 38707, FAC 101, the Hearing Transcript, at p. 22, line 14-24 shows the following statements:

> In Edwardsport's case, the unit is run for -- again, it's like the testing and tuning and optimization, for the long-term benefit of the customer, not necessarily -- we're not necessarily moving it around each hour at this point in time. That does change in September of this year.
>
> Q So Duke has been testing, tuning, and optimizing the unit up to this outage?
>
> A When the unit was available on syngas and not testing on natural gas, that's correct.

Additionally in Cause No. 38707 FAC 101, the Hearing Transcript, at p. 18, line 14 – p. 19, line 8, states as follows:

> Q And when you must-run Edwardsport as you've done ever since it started, do you must-run it at the maximum?
>
> A Well, just to be clear, we must-run the unit when syngas was available and producing and/or the unit was testing on natural gas.
>
> Q Before you go on, let me say, isn't -- hasn't that been all the time since the plant has run?
>
> A No.
>
> So there have been times when the plant was not available on syngas and not testing on natural gas, and we made an offer of -- a commitment status of economic to MISO, and the unit did clear one time in that example.
>
> Q When was that?
>
> A On May 28th, the unit was offered with a commit status of economic, and the unit was picked up in the Day Ahead market by MISO.

Also see, the Direct Testimony of Joint Intervenors witness Schlissel, and Petitioner's responses to discovery.

Q. During the period of June 7, 2013 through February 28, 2014, relative to the operation of the Edwardsport IGCC generating station, by individual calendar date, for what number of hours during this period was the output of the station classified by Petitioner as Testing?

A. This was asked of Petitioner in data request CAC 2.1(a). Petitioner's response indicates that for <u>all</u> hours of Edwardsport IGCC generation from June 7, 2013 through February 28, 2014 was classified as Must Run for MISO dispatch, and was categorized by Petitioner as testing.

Q. During the period of June 7, 2013 through February 28, 2014, relative to the operation of the Edwardsport IGCC generating station, was any of the Edwardsport IGCC generation dispatched by MISO on an economic basis?

A. No. Petitioner's response to CAC 2.1(a) indicates that <u>none</u> of the Edwardsport IGCC generation in any hour during the period June 7, 2013 through February 28, 2014 was dispatched by MISO on an economic dispatch basis:

> **All hours Edwardsport ran during the time period in question have been categorized as "testing,"** with assignment to native load, for purposes of stacking generation in the Company's PACE model. This is consistent with the Company's categorization of generation during testing periods at other generating units. **Note that during the time period in question, Edwardsport was not cleared by MISO while being offered with a commitment status of "Economic" in any hour and thus, all generation was the result of a "Must Run" commitment status.** In addition, see Attachment CAC 2.1 A, which represents the real-time generation, as well as the day-ahead asset energy, real-time non-excessive, and real-time excessive energy amounts from Edwardsport. Note that this represents only the revenues as a result of the units' participation in only the MISO energy markets. To calculate all "resulting revenues," additional credits and adjustments from ARRs/FTRs, capacity, ancillary services, distribution of losses, make whole payments, etc. would need to be included.

(Emphasis supplied.)

A copy of Petitioner's response to CAC 2.1 is included in Exhibit LA-16, attached hereto.

Q. If the generation of electricity using gasified coal at the Edwardsport IGCC is still in an extensive testing phase, should the plant be treated for accounting and ratemaking purposes as being "in service" for commercial operation?

A. No. The Petitioner's operation of this plant for testing purposes using gasified coal only for a few days in June 2013 (at a level below full capacity) and then shutting it down for extensive repairs and further testing, which has continued through March 31, 2014 and beyond, is simply inconsistent with "commercial" operation of the plant as an integrated coal gasification combined cycle plant. Accordingly, the Commission should order Petitioner to make a compliance filing consistent with Findings that the Edwardsport IGCC was **<u>not</u>** in or ready for commercial operation during the combined IGCC-12 and 13 review periods.

Q. Is a June 7, 2013 in-service date consistent with Petitioner's own representations about when the plant would be declared "in-service"?

A. No. I note further that Petitioner's response to CAC 4.4 in IGCC-8[12] expressly stated that the plant will not be declared in-service for accounting and ratemaking purposes until testing is completed and the plant is ready for service for its intended use as an "integrated gasification combined cycle" generating facility:

> Duke Energy Indiana states as follows: The "initial start-up and generation of test power for sale" occurs while the plant is still in test phase, which is earlier than when the plant will be declared as in-service for accounting and ratemaking purposes. **The plant will be declared in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.**
>
> (Emphasis supplied.)

[12] This response is reproduced in Exhibit LA-3, attached hereto.

Thus, DEI has **not** achieved its intended use of Edwardsport is as an integrated gasification combined cycle generating facility that produces electricity at a capacity factor using gasified coal consistent with a commercial level of operation.

Q. What do you recommend?

A. The Commission should deny most of the Petitioner's request for relief in this Cause on the grounds that the Edwardsport IGCC did not achieve commercial operation during the IGCC 12 or 13 review periods, continued to be in extensive testing during these periods, and was not operated under MISO economic dispatch during these periods. As explained by Mr. Schlissel, when Edwardsport did run, it experienced poor output and a high heat rate, thus making the plant's output uneconomic during the combined IGCC-12 and 13 review periods.

The Commission should also direct in its order concluding the present proceedings that these conclusions and other related regulatory matters be addressed in a compliance filing by DEI and later responsive filings by the non-Duke parties, which should be the subject of further hearing and order.

Q. Have you been able to quantify the impacts of the Edwardsport IGCC not being in commercial operation during the combined IGCC 12 and 13 review periods?

A. Not fully. As shown on Exhibit LA-13, I have identified the operating expenses including O&M expense, property taxes and depreciation expense that DEI has claimed for actual expenses in the IGCC-12 and 13 periods. If the Commission agrees with the Joint Intervenors' position that the Edwardsport IGCC was not in commercial operation as a gasified coal-fired IGCC (i.e., for its intended use) during this period, then these operating expenses should be disallowed. As shown there, I have estimated that the reduction should be approximately $141.5 million, before any potential additional AFUDC is considered. This calculation does not incorporate additional return on CWIP from additional post June 7, 2013 AFUDC accruals, which Petitioner may claim that it is entitled to under the terms of the Settlement Agreement. The impact of potential additional AFUDC has not been quantified, but if allowed by the Commission, would lower the amount of the $141.5 million cost disallowance related to the Edwardsport IGCC not being in commercial operation during the combined IGCC 12/13 review periods. Unfortunately, the situation presented here presents a complex inter-relationship among multiple factors and considerations which almost certainly will require another round of filings, hearing and order to address and resolve, at least in my opinion. As noted above and explained below, I am recommending that the Commission should direct in its order concluding the present proceedings that this disallowance and other related regulatory matters be addressed in a compliance filing by DEI and later responsive filings by the non-Duke parties, which should be the subject of further hearing and order.

Q. Should a Commission-ordered DEI compliance filing be required to address other aspects of the Edwardsport IGCC not being in commercial operation during the IGCC-12 and 13 review periods?

A. Yes. The compliance filing should require DEI to re-file its IGCC-12 and 13 revenue requirements on the basis that the Edwardsport IGCC was <u>not</u> in commercial operation during either of these review periods, i.e., was not in commercial operation through March 31, 2014, the ending date of the IGCC-13 review period.

Q. If it were to be assumed that Edwardsport was "actually used and useful for the convenience of the public" as of June 7, 2013, has DEI demonstrated that the actual operating costs it is claiming for Edwardsport during the IGCC-12 and 13 review periods are reasonable?

A. No. DEI has failed to demonstrate that, even assuming that Edwardsport was "actually used and useful for the convenience of the public" as of June 7, 2013, the operating costs of approximately $184 million and $187 million claimed by the Company as the Edwardsport operating revenue requirement for retail ratemaking purposes for the six month periods in IGCC-12 and IGCC-13, respectively, are "reasonable and necessary" in their entirety.

Q. What other important issues should be addressed in a Commission-ordered compliance filing?

A. Other important issues that should be addressed in such further proceeding should include the following:

- Were the Commission to reach the conclusion, notwithstanding Joint Intervenors strongly held position to the contrary, that Edwardsport was "actually used and useful for the convenience of the public" as of June 7, 2013, some significant part of the revenue requirement claimed by the Company for the IGCC-12 and 13 review periods should be subject to disallowance for retail ratemaking purposes as excessive in relation to actual plant performance compared to prior Petitioner representations to assure reasonable levels of O&M costs for the Edwardsport IGCC. In particular, the Commission should address in its findings and direct the Company to address in their filings these key issues:
- Is the Company properly classifying costs which it is capitalizing following its June 7, 2013 "in service" declaration between "construction costs" subject to the "hard cap" approved in Cause No. 43114-IGCC-4S1, and "operating costs" not subject to the cap? Is the Company converting its October 2012 estimate of $3.55 billion in construction costs into a "self-fulfilling prophecy" by classifying a significant amount of startup, testing, commissioning and repair costs incurred since June 7, 2013 as operating costs rather than construction costs?
- In view of the plant's relatively poor operating performance since Petitioner's June 7, 2013 "in service" declaration, should the remaining Edwardsport revenue requirement charged to customers be moderated to correspond with the extended post "in service" period of time that is being required for the plant to achieve a truly "commercial" level of operation and cost of generation?

Q. Can these important issues be adequately addressed at this time in the current consolidated IGCC-12 and 13 review proceeding?

A. Not fully. Because of the importance and complexity of these accounting and ratemaking issues, it is my opinion that they cannot be adequately investigated and evaluated at this time in the consolidated IGCC-12 and 13 proceeding. Instead, as previously indicated, it is my opinion that these issues should be addressed initially in a DEI Compliance Filing in response to the Commission order concluding the investigation phase of the current proceeding, and then subsequently in further testimony by the Non-Duke parties with those filings subject to further hearing and order.

Q. What is your recommendation of how any further rate increases related to the Edwardsport IGCC should be treated, pending the needed further proceedings?

A. Any further rate relief requested by the Company on account of Edwardsport, including the rate increases requested by the Company in IGCC-11, 12 and 13 as well as any rate increase requested in IGCC-14 or later rider or rate case proceeding, should either be deferred or made subject to refund pending the conclusion of the Compliance Filing proceedings referenced above.

V. NEED FOR PERFORMANCE STANDARDS AND AN OPERATING COST CAP TO PROTECT RATEPAYERS FROM EXCESSIVE COSTS AND POOR PLANT PERFORMANCE

Q. Is there a need for performance standards and an operating cost cap to protect Indiana Retail ratepayers from excessive costs and poor performance of the Edwardsport IGCC facility, as Mr. Schlissel has recommended?

A. Yes. The construction of the Edwardsport IGCC was justified to the Commission on the basis of certain standards of expected operating performance, including capacity factors and heat rate. In addition, the settlement that was agreed to by various other parties (not Joint Intervenors) and was approved by the Commission in IGCC-4S1 after the Commission reviewed and accepted the representations made by DEI about levels of operating expenses and projections of operating performance for the Edwardsport IGCC. Given the Company's serious failure to meet its past representations to its customers and its regulators, the Commission should establish performance standards and an operating cost cap to protect both itself and DEI's customers against a repeat occurrence in the future.

Q. What capacity factor standard should be applied for the IGCC-12 and 13 review periods?

A. Joint Intervenors witness David Schlissel addresses this and recommends a capacity factor of 72 percent be used as the standard for the combined IGCC-12 and 13 review periods, if the Commission determines that Edwardsport was actually in commercial operation during that time. As Mr. Schlissel explains, DEI represented to their customers and their regulators that the Edwardsport IGCC would achieve a 72 percent capacity factor during its first year to 15 months of operation, which would extend through September 2014 under that scenario.

Q. What performance factor would be applied for subsequent periods?

A. For subsequent periods, I concur with Mr. Schlissel that the Company should be held to the higher standard which it set for itself in IGCC-4S1, namely a performance standard that requires that the Company, not ratepayers, bear all costs resulting from the plant's failure to achieve an 82 percent capacity factor while burning syngas during each twelve-month period following the end of Edwardsport's first 15 months of commercial operation, whether that is September 30, 2014, or a much later time, as Joint Intervenors have recommended.

Q. How has the Edwardsport IGCC performed during the combined IGCC 12 and 13 review periods in relation to such standards?

A. As summarized in Mr. Schlissel's testimony, during the combined IGCC-12 and 13 review periods, from the Company's declared "in service" date of June 7, 2013 through March 31, 2014, the Edwardsport IGCC achieved an operational performance that is much worse than a level that would be consistent with commercial operation of the plant, and much worse than the 72 percent that Petitioner had previously represented that the plant would be expected to achieve during the first year to 15 months of operation. Among other facts noted by Mr. Schlissel, the Edwardsport actual generation from June 2013 when the plant was declared to be 'in service' through the March 31, 2014 end of the IGCC-13 review period was only 45 percent of what the Company had forecast for this period at the end of 2012, which is significant because it was Duke, not MISO, which determined when and for how long Edwardsport would operate.[13]

Q. What are the ramifications of the Edwardsport IGCC having produced such poor performance during the IGCC-12 and 13 review periods, as compared with what it was supposed to achieve during its first year to 15 months of operation?

A. The ramifications are that, without an appropriate ratemaking disallowance, Indiana Retail ratepayers would pay way too much for Edwardsport generation, based on the very wide gap between the projected performance that was used by Petitioner in justifying the plant and its actual performance achieved during the IGCC-12 and 13 review periods.

Q. What Edwardsport costs should be addressed in a performance adjustment?

A. The construction cost of the generating plant was capped in the IGCC-4S1 Settlement and Order. Here, the return on and of that cost (i.e., the return component and

[13] See, e.g., Joint Intervenor Exhibit B, Direct Testimony of David A. Schlissel, at pages 23-24.

depreciation expense) as well as the fixed operating costs of the plant during the combined IGCC-12 and 13 review periods should be addressed in a performance adjustment.

Q. Is the Hard Cost Cap that was agreed to by other parties in the Settlement Agreement protecting Indiana ratepayers from costs associated with the poor operating performance of the Edwardsport IGCC during the IGCC 12 and 13 review periods?

A. No, it is not. The "hard cost cap" is supposed to be for the construction cost of an Edwardsport IGCC facility that is supposed to operate as a base load facility with a rated capacity of 618MW (October through May) or 586MW (June through September) and which was supposed to achieve a capacity factor of 72 percent for its initial year to 15 months of operation. It was not intended to address issues relating to the plant's operating cost and performance. The facts documented by Joint Intervenors witness Schlissel show that during the IGCC-12/13 review period, the plant operated far below levels that would be consistent with commercial operation of the plant as an integrated gasification combined cycle plant that would be economically dispatched by MISO. The fixed costs of the plant, including return and depreciation, are being charged to Indiana Retail ratepayers but the plant has not produced a level of net generation during the IGCC-12/13 review period consistent with commercial operation or at the performance levels previously represented by Petitioner. The "hard cost cap" thus provides no protection to Indiana Retail ratepayers for the very poor operating performance of the Edwardsport IGCC documented by Mr. Schlissel that has occurred during the IGCC-12 and 13 review periods.

Q. Should the Commission consider an adjustment in the IGCC-12 and 13 review periods that protects Indiana Retail ratepayers from the excessive costs of Edwardsport that are associated with the poor plant performance during these review periods?

A. Yes. The Edwardsport IGCC cost for production plant return and depreciation can be adjusted to reflect the fact that the plant performed poorly during the IGCC-12 and 13 review periods, and that its achieved performance during these review periods was substantially lower than the 72 percent standard explained by Mr. Schlissel that had been represented for this plant.

Q. Have you provided an illustrative calculation of an adjustment to protects Indiana Retail ratepayers from the excessive costs of Edwardsport that are associated with the poor plant performance during the IGCC-12 and 13 review periods?

A. Yes. On Exhibit LA-14, I show an illustrative calculation to reduce the amounts of return on the Edwardsport IGCC and the related depreciation expense in direct proportion of the achieved Edwardsport performance versus the intended performance that Petitioner used to justify the plant to the Commission, using the percentage adjustment supplied to me by Mr. Schlissel, based on his analysis of the relative performance gap. This would reduce the revenue requirement requested by DEI for IGCC-12 and 13 by approximately $161.2 million.

Q. What other standards are needed?

A. Mr. Schlissel proposes additional standards for the plant's heat and carbon dioxide (CO2) emissions rates. I address the need for an operating cost cap.

Q. What is a heat rate?

A. A "Heat Rate" is a broad measure of thermal efficiency of a power plant in the conversion of fuel into electricity. It measures the amount of heat input in Btus per hour for each kilowatt-hour of electricity produced. For most purposes, the heat rate is expressed in MMBtu per MWh.

Q. What heat rate standard has been identified by Mr. Schlissel?

A. A heat rate of 9,313 MMBtu per MWh has been identified by Mr. Schlissel as an appropriate standard for the Edwardsport IGCC for the combined IGCC-12 and 13 review periods.

Q. During the combined IGCC-12 and 13 review periods, how did the actual performance at the Edwardsport IGCC compare with that heat rate standard?

A. During the IGCC-12 and 13 review periods, information was obtained from DEI in response to discovery and is summarized in the Direct Testimony of Joint Intervenors witness Schlissel at pages 28-29 and in his Figure 9, which shows that Edwardsport's actual monthly heat rates have been significantly worse than the Company told the Commission back in April 2010.

Q. Have you identified any adjustment at this time to Edwardsport IGCC costs that are recovered through the Rider 61 process associated with the heat rate performance of the Edwardsport facility during the combined IGCC-12 and 13 review periods?

A. No, I have not. The poor heat rate performance experienced by Edwardsport during the combined IGCC-12 and 13 review periods would appear to primarily affect fuel and power costs, which are addressed in FAC proceedings. In terms of those costs that were incurred at Edwardsport to generate electricity during the IGCC-12 and 13 review periods due to the poor heat rate performance on average, larger amounts of fuel (i.e., associated with the higher quantities of BTUs/MWH) were needed to produce the amount of MWhs that were generated by the plant. Other than fuel and purchased power costs, which are addressed in separate FAC proceedings, I have not been able to identify other costs included in the IGCC review proceedings that would need to be adjusted for the poor heat rate performance experienced at Edwardsport IGCC plant during the IGCC-12 and 12 review periods that is discussed by Mr. Schlissel.

Q. What is a CO2 emissions rate?

A. A CO2 emissions rate is the quantity of CO2 emitted by a generating facility divided by its generation and is typically measured in tons or pounds per megawatt hour.

Q. Has Mr. Schlissel proposed a performance standard the Edwardsport CO2 emissions rate?

A, Yes. He has proposed that Duke shareholders rather than DEI customers bear any future costs resulting from Edwardsport emitting CO2 at a rate higher than the Company represented in the proceedings in which the plant was approved, namely 1556 pounds per megawatt hour.

Q. Did Edwardsport meet this performance standard during the IGCC-12 and 13 review periods?

A. No. According to Mr. Schlissel's testimony, the Edwardsport CO2 emissions rate significantly exceeded this performance standard.

Q. Are you proposing a ratemaking adjustment at this time for this failure of Edwardsport to meet the emissions rate standard recommended by Mr. Schlissel?

A. No, not at this time. Mr. Schlissel has advised that, given the current regulatory regime for CO2 emissions, the excess CO2 emitted by Edwardsport will not result in a current financial penalty to DEI ratepayers during the IGCC-12 and 13 periods or likely do so in the near future under the Clean Power Plan recently proposed by the Environmental Protection Agency.

Q. Was information presented in IGCC-11 that can be helpful in developing an operating cost cap?

A. Yes. In the IGCC-11 proceeding, DEI-IG Cross Examination Exhibits CX-2 through CX-5 and the related Transcript from IGCC-11 are helpful.[14] In the IGCC-11 proceeding, these exhibits were subject not only to cross examination by counsel for DEI-IG, but also by redirect from counsel for DEI. In particular, IGCC-11 DEI-IG Cross Examination Exhibit CX-2 provides baseline information that can be used to help evaluate the reasonableness of Edwardsport IGCC operating costs in relation to past Company projections. The other related IGCC DEI-IG Cross Examination Exhibits and the related cross examination are also helpful because they have relevance to the Edwardsport IGCC operating costs and provide additional context for CX-2 as well.

Q. Why do IGCC-11 DEI-IG Cross Examination Exhibits CX-2, CX-4, and CX-5 provide a useful frame of reference?

A. IGCC-11 DEI-IG Cross Examination Exhibits CX-2, CX-4, and CX-5 provide a useful frame of reference because they compare Edwardsport IGCC operating costs claimed by the Company in IGCC-11 with the original CPCN proceedings, Cause No. 43114, and with DEI's numbers in its most recent CPCN amendment proceedings, Cause No. 43114-IGCC-4S1. DEI-IG Cross Examination Exhibits CX-2, CX-4, and CX-5 from IGCC-11 contain information on Petitioner's estimates of operating costs for the Edwardsport IGCC that can be used in comparison with the much higher operating costs Petitioner is claiming for the Edwardsport IGCC for the IGCC-12 and 13 review periods. This comparison is shown on Exhibit LA-15.

Q. Please explain how that information can be applied in the IGCC-12 and 13 review periods.

[14] For ease of reference, DEI-IG Cross Examination Exhibits CX-2, CX-4, and CX-5 are attached to my testimony in Exhibit LA-11.

A. I have used IGCC-11 DEI-IG Cross Examination Exhibit CX-4 and CX-5 as a comparison to the DEI revenue requirements for Edwardsport IGCC operating expenses in IGCC-12 and 13.

Q. What are the implications of the comparison of Edwardsport IGCC operating costs?

A. Exhibit LA-15 presents an illustrative calculation of excessive operating expenses and quantifies the amount at approximately $18.5 million for the IGCC-12 and 13 review periods.

VI. UNREASONABLY HIGH COST OF THE EDWARDSPORT IGCC DURING THE IGCC-12 AND 13 REVIEW PERIODS

Q. What issues will you be addressing in this section of your testimony?

A. In this section of my testimony, I address the cost of Edwardsport to Indiana jurisdictional ratepayers. Coupled with the testimony of Mr. Schlissel about the plant's poor performance during the IGCC-12 and 13 review periods, and of the continuing operational problems experienced at the plant, and the inability of the plant to achieve or sustain a level of output consistent with commercial operation, this information demonstrates how the level of costs during the IGCC-12 and 13 periods is unreasonably high and supports the implementation of an operating expense cost cap and operating performance standards.

Q. Is it necessary for DEI to demonstrate that the costs are reasonable and necessary for them to be recoverable?

A. Yes. I am advised by counsel that Indiana Code § 8-1-8.8-12 (d) requires that the utility must document that the costs associated with qualified utility system property and the schedule for incurring those costs are reasonable and necessary.

Q. Are the costs for the Edwardsport IGCC during the IGCC-12 and 13 review periods reasonable?

A. No. As described herein and in the testimony of Mr. Schlissel, during the IGCC-12 and 13 review periods the Edwardsport IGCC operated poorly and its costs were not economic. Because Edwardsport experienced serious operational problems and was continuing to undergo extensive testing during the IGCC-12 and 13 review periods, as described by Mr. Schlissel, it did not operate economically during this period, and it experienced unreasonably high costs.

Q. What amount of revenue has DEI collected from Indiana Retail ratepayers for Edwardsport so far?

A. As shown on Exhibit LA-12, through September 30, 2013, DEI had collected $500,328,918 from Indiana Retail ratepayers for Edwardsport, of which $470,989,559 was for CWIP and $29,339,359 was for other costs.[15] For the six-month IGCC-13 period, DEI collected an additional $179.8 million, of which $148.5 million was for CWIP and approximately $31.3 million was for other costs. In total, through March 31, 2014, DEI shows Rider 61 revenues for the Edwardsport IGCC of approximately $627.973 million.

Q. What amount of net generation has the Edwardsport IGCC produced since the June 7, 2013 date when DEI declared the plant to be "in service"?

A. For the months of June 2013 through March 2014, the Edwardsport IGCC had the following amounts of net generation[16]:

[15] See, e.g., IGCC-12, DEI witness Diana Douglas' workpaper 12.

[16] Counsel for Petitioner confirmed with Joint Intervenor counsel that Edwardsport net generation on a monthly or longer period basis does not need to be treated as being confidential. Similar monthly net generation information is available from the Energy Information Administration (EIA) on a public basis.

Edwardsport IGCC Net Generation				
Line No.	Month	Year	Edwardsport Actual Net Generation (MWH) [Source 1]	Edwardsport IGCC Production Net MWH [Source 2]
			(A)	(B)
1	June	2013	55,074	55,074
2	July		120,438	120,438
3	August		277,691	277,691
4	September		140,853	140,853
5	October		199,129	199,129
6	November		125,820	125,820
7	December		148,918	148,918
8	January	2014	80,641	80,641
9	February		21,632	21,632
10	March		150,678	150,678
11	Totals		1,320,874	1,320,874
Notes and Source				
Col.A:	CONFIDENTIAL RESPONSE to DEI-IG 4.24			
Col.B:	CONFIDENTIAL RESPONSE to DEI-IG 6.1d			

Q. Have you included estimated fuel costs for the Edwardsport IGCC?

A. Yes. Using information publically reported on the Energy Information Administration form 923 that was provided to me from a Joint Intervenor consultant, I have included estimated fuel costs for the Edwardsport IGCC for the months of June 2013 through March 2014.

Q. Have you made an estimate of the per-kWh cost to the Indiana Retail ratepayers of the Edwardsport IGCC during the IGCC-12 and 13 review periods?

A. Yes. To estimate the impact on Indiana Retail ratepayers of the Edwardsport IGCC through the end of the IGCC-12 and 13 review period, I divided the amounts DEI has collected through March 31, 2014 by the Edwardsport net generation through that same date. As shown on Exhibit LA-12, this produces a cost for Edwardsport of $567.81 per MWH, or approximately 57 cents per-kWh.

Q. Would the per-kWh cost be higher than that if the actual operating expenses that DEI shows for the IGCC-12 and 13 review periods were factored in?

A. Yes. The Rider 61 rates charged to Indiana Retail ratepayers for the IGCC-13 period have been based upon the rates established in IGCC-10, and thus have not yet incorporated the full impact of the high operating costs that have been incurred for the Edwardsport IGCC during the IGCC-12 and 13 review periods.

Q. What is the reason that the cumulative from inception cost of 57 cents per kwh is so much higher than the cumulative from in-service declaration cost of 34 cents per kwh?

A. Actually, there are two reasons. First, Indiana law currently authorizes what is commonly known as “Cash on CWIP” ratemaking treatment for utility projects like the Edwardsport IGCC. This means that utilities are permitted to earn a profit on their investments in projects while they are still under construction. Second, Edwardsport has been under construction for a very long time, approximately two years longer than the Company originally predicted when it originally sought approval from the Commission back in 2007. As a result, the Company charged its customers almost $400 million in “Cash on CWIP” before the Company declared Edwardsport to be in service. This is a very heavy front end financial load on DEI customers which will inevitably require many years and much improved operating and cost performance to gradually winnow down to per kwh costs even approaching reasonable levels.

Q. Have you prepared a calculation of the per-kWh cost of the Edwardsport revenue requirements that Petitioner has requested for the combined IGCC 12 and 13 review periods, using the net generation of the Edwardsport IGCC during these periods?

A. Yes. As shown below, I divided DEI's requested revenue requirements for the IGCC 12 and 13 review periods by the Edwardsport IGCC net generation during DEI's declared "in service" portion of this period, i.e., from June 7, 2013 through March 31, 2014:

IGCC-12 and 13 Revenue Requirements Divided by Net Generation			
Description	Amount Without Fuel Costs	Amount With Estimated Fuel Costs	Source
Petitioner's Requested Revenue Requirement:			
IGCC-12	$ 184,099,276	$ 184,099,276	[A]
IGCC-13	$ 187,371,993	$ 187,371,993	[B]
Estimated Fuel Costs		$ 60,500,000	[C]
Total for IGCC-12 and 13 Combined	$ 371,471,269	$ 431,971,269	
Edwardsport IGCC net generation through March 31, 2014 in MWHs	1,320,874	1,320,874	[D]
Cost per MWh of Edwardsport net generation	$ 281.23	$ 327.03	

Notes and Source

[A] IGCC-12 Petitioner's Exhibit C-2, page 9, column I, line 15

[B] IGCC-13 Petitioner's Exhibit B-2, page 10, column I, line 15

[C] Estimated fuel costs derived from EIA Form 923 Information. See Ex. LA-12

[D] Column I: Petitioner's responses to DEI-IG 4.24 and DEI-IG 6.1d that had been marked CONFIDENITAL by DEI but DEI has confirmed to Joint Intervenor counsel that net generation information aggregated monthly or higher does not need to be confidential. Similar information is available from public sources.

This produces a per-kWh cost for Edwardsport of approximately 28.1 cents without estimated fuel costs and approximately 32.7 cents with estimated fuel costs.

Q. Is there a reason why the per-kWh cost of Edwardsport is so high in total, and during the IGCC 12 and 13 review periods?

A. Yes. As explained in the testimony of Mr. Schlissel, during the IGCC 12 and 13 review periods, the plant has operated poorly. Through March 2014 it was continuing to undergo extensive testing. It was not operated economically. During the combined IGCC-12 and 13 review periods, the plant's achieved heat rate was very poor. For some months of the IGCC 12 and 13 review period, the Edwardsport IGCC heat rate was worse on average than DEI's combustion turbine peaking units. As Mr. Schlissel also explains, the parasitic load as a percentage of net plant output was very high, much higher than DEI had represented when attempting to economically justify the plant to the Commission. All of these factors have contributed to the extremely high per-kWh cost of the Edwardsport IGCC during the IGCC 12 and 13 review periods.

Q. Is there a need for an operating expense cost cap and performance standards?

A. Yes. In order to assure that Indiana Retail ratepayers are paying only for reasonable costs, and are not paying for unreasonable or uneconomic costs, an operating expense cost cap and performance standards would appear to be needed.

Q. Are you familiar with the conceptual framework that has been articulated by another regulatory commission where an IGCC was authorized based upon representations of cost, performance, and economic expectations presented by a utility?

A. Yes. In its April 24, 2012 Order in Case No. 2009-UA-01, the Mississippi Public Service Commission (Final Order on Remand), articulated the following conceptual framework in the context of the Kemper IGCC that is being constructed by Mississippi Power Company to protect Mississippi ratepayers from potential poor operational performance:

> "The operational cost and performance parameters assure that ratepayers will not pay for an underperforming asset." ¶ 10

> "Put simply, if Kemper doesn't perform as advertised then the ratepayers will not pay for it." ¶179

Q. How does the "reasonable and necessary" standard protect Indiana Retail ratepayers?

A. I am advised by counsel that the requirement in Indiana Code § 8-1-8.8-12 (d) that costs be "reasonable and necessary" would accordingly require that unreasonable, uneconomic, or imprudent costs should not be charged to Indiana Retail ratepayers.

Q. Have the Edwardsport IGCC costs during the IGCC-12 and 13 periods included uneconomic costs and/or exceeded levels that could be considered "reasonable and necessary" and thus represent excessive costs that should not be charged to Indiana Retail ratepayers?

A. Yes, I believe so.

Q. Have you been able to quantify the amount of excessive costs under review in the IGCC-12 and 13 proceedings that should be disallowed?

A. Not exactly, but I have made an estimate and show an illustrative framework for calculating an adjustment to remove costs based on the poor performance of the Edwardsport IGCC during the IGCC-12/13 review periods on Exhibit LA-14 and an illustrative calculation of excess operating costs on Exhibit LA-15.

Q. What is your recommendation?

A. As indicated earlier in my testimony, I recommend that the Commission issue an order with its findings and conclusions from the investigatory phase of this consolidated IGCC-12 and 13 proceeding in which it directs DEI to make a filing to comply with those findings and conclusions, after which the non-Duke parties would make their responsive filing, followed by a further hearing and order by the Commission.

VII. CONCERN THAT DEI IS CLASSIFYING COSTS IN A MANNER TO EVADE THE "HARD COST CAP" AND THAT IS INADEQUATELY DOCUMENTED, NOT TRANSPARENT AND CANNOT BE ADEQUATELY REVIEWED

Q. What has DEI stated about its process for classifying costs between categories that are subject to the "hard cost cap" and categories which are not subject to that cap?

A. DEI's supplemental response to CAC 10.2 states that:

> As discussed in the response to CAC 10.6, the Company follows FERC accounting guidance (specifically Electric Plant Instruction 10 from Title 18, Chapter I, Subchapter C, Part 101 of the Code of Federal Regulations) for determining whether the cost of maintenance work should be expensed or capitalized.
>
> In addition and to the extent this Request is seeking information regarding “normal ongoing capital maintenance” under the Settlement Agreement, **<u>the Company holds meetings on a regular basis with a cross-functional team (including station, rates, legal, and accounting personnel) where each new capital project established for Edwardsport station is discussed and</u>**

> **evaluated in the context of Item 2E of the Settlement Agreement and classified accordingly as an expenditure for ongoing capital maintenance or as an expenditure that should be subject to the Hard Cost Cap**. This classification is based upon the circumstances that gave rise to the capital project, not upon specific work orders or accounting documentation. Refer to Confidential Workpapers 9 through 11 filed in IGCC 12 and Confidential Workpapers 9 through 12 filed in IGCC 13 for additional accounting details of the post-in-service ongoing capital projects.
>
> (Emphasis supplied.)

Q. Do DEI's Confidential Workpapers 9 through 11 filed in IGCC-12 and its Confidential Workpapers 9 through 12 filed in IGCC-13 provide complete accounting details and information showing in a transparent manner exactly how DEI has classifying costs between categories that are subject to the "hard cost cap" and categories which are not subject to that cap?

A. No. The referenced workpapers contain some information on where the costs ended up in DEI's accounting system but the Petitioner's presentation does not provide a transparent review trail of exactly how each new capital or maintenance project established for Edwardsport station was discussed and evaluated in order to document DEI's decision to classify it as an expenditure which is subject to the "hard cost cap" or one which is not subject to the cap.

Q. Why are work orders for capital projects and significant maintenance projects significant and relevant?

A. Work orders for capital projects and significant maintenance projects significant and relevant because they usually contain details about the work being performed, the authorizations to perform it and contain information on the costs that were approved for the work, as well as justification for why the work is needed, and the time frame for performing it.

Q. Are there concerns that DEI's cost classification is resulting in evasions of the "hard cost cap" and is inadequately documented, not transparent, and cannot be adequately reviewed?

A. Yes. DEI's responses to date do not provide a transparent and reviewable documentation trail of the costs that Duke believes are covered by the "hard cost cap," and does not provide a clear indication of the costs that Duke believes are an exception to the "hard cost cap," and more importantly, fails to provide details concerning Duke's reasoning and standards for the underlying classifications. Also, the fact that Duke is apparently relying on the fact that it "holds meetings on a regular basis with a cross-functional team (including station, rates, legal, and accounting personnel) where each new capital project established for Edwardsport station is discussed and evaluated in the context of Item 2E of the Settlement Agreement and classified accordingly as an expenditure for ongoing capital maintenance or as an expenditure that should be subject to the Hard Cost Cap,"[17] makes it highly important that a full and complete response is both relevant and necessary. For reasons similar to these, Joint Intervenors asked the Commission that Duke be compelled to fully respond to JIs' Data Request 10.2, providing the following information:

> 1. Work orders and accounting documents relating to the determination of whether ongoing capital maintenance projects are subject to the "hard cost cap";
>
> 2. A clear indication of how Duke determines whether the costs of repairs to Edwardsport are subject to the "hard cost cap" and Duke's reasoning and standards for the underlying classification; and
>
> 3. A clear indication of how Duke determines whether the costs of repairs are an exception to the "hard cost cap" and Duke's reasoning and standards for the underlying classification.

The Commission granted this request and Joint Intervenors followed up on the Company's supplement responses with five more sets of related discovery requests,

[17] See, e.g., Duke's response and supplemental response to CAC Data Request 10.2.

the last two of which they received only a week before this testimony is due. As a result, Joint Intervenors now have now obtained most of the basic information needed to conduct a preliminary review of the Company's claimed O&M capital and maintenance projects in IGCC-12 and 13 to assess the Company's compliance with the provisions of the IGCC-4S1 Settlement, but have neither all of the information nor the time needed to quantify the extent of the Company's non-compliance.

This information is highly relevant and needed to address and pursue the concerns that DEI's cost classifications are resulting in evasions of the "hard cost cap" and are inadequately documented, not transparent and cannot be adequately reviewed.

Q. Please explain the concern that DEI is claiming certain repair and related costs as Operating and Maintenance (O&M) expenses for purposes of retail rate recovery, which, under the Settlement, should be classified as Construction Costs subject to the Hard Cost Cap.

A. Section 2.E of the Settlement approved by the Commission in Cause No. 43114-IGCC-4S1 with modifications not relevant here states:

> E. "Construction Costs" of the Project shall be defined in accordance with usual utility practices and in accordance with FERC guidelines and **<u>includes all costs required to achieve "final completion," as that term is defined in the December 20, 2007 contract between Duke Energy Indiana and GE (see Attachment A), such as engineering, materials, construction and equipment purchases, capitalized AFUDC (through June 30, 2012), and all start-up and testing, validation and commissioning costs, and costs of repairs and modifications identified during start-up, testing, validation and commissioning and all such costs required whether actually disbursed or only obligated during such period, as well as any costs subsequently incurred to pay claims disallowed or unpaid during such period; except that: "Construction Costs" of the Project and the Hard Cost Cap shall not include normal operating and maintenance ("O&M") expenditures on the Project, which, according to FERC guidelines, begin after the "In Service Operational Date" and shall not include subsequent ongoing capital spent on the Project for normal capitalized repairs or maintenance expenditures or additional plant and equipment necessary for the continued operation of the Project after the "In-Service Operational Date", unless identified during start-up, testing, validation and</u>**

> **commissioning as being necessary to reach "final completion"**, nor does the cap apply to orders of the Commission approving cost recovery related to carbon capture and storage (including study costs) involving the Project.
>
> (Emphasis supplied.)

In this context, I am concerned that substantial costs claimed by the Company as operating and maintenance expenses should have been classified as “construction costs” under the Settlement because, as explained by Joint Intervenors witness Schlissel, as a factual matter, they were incurred for "repairs and modifications identified during start-up, testing, validation and commissioning as being necessary to reach 'final completion.'"

Mr. Schlissel will explain the technical aspects of this matter in his testimony. Explaining the related accounting concerns is my responsibility.

Q. Did Petitioner change the accounting default for Edwardsport costs to O&M expense, effective upon its declaration of "in service" on June 7, 2013?

A. Yes. A bullet point from the Edwardsport post-in-service accounting guide that was identified in response to CAC DR 10.16 as CAC Attachment 10.16-A, which is the accounting guide/training document on which CAC discovery questions in CAC DR Set 13 were based, on the page identified as page 15 of 17 (BS 090015313-0006024), states as follows:

> Default accounting will need to be updated in the expense system when we go commercial. Your new default accounting will be O & M and you will use a work order for any capital or closeout expenses you may have.

This switch to "new default accounting" as O&M appears to mean that unless affirmative action is taken by plant personnel to classify a cost as either capital or closeout, it is classified as O&M expense by default. Thus, after the declaration of the Edwardsport IGCC being "in service" on June 7, 2013, unless Edwardsport costs are specifically singled out for accounting as construction costs, Petitioner is accounting for them as O&M expense. Petitioner is subjecting to special review and capitalizing a very small proportion and is expensing without special review the vast majority of Edwardsport costs from June 7, 2013 through March 31, 2014.

Q. Can you please elaborate on the concern that during the IGCC 12 and 13 review periods, the "new default accounting" as O&M, coupled with the lack of review by the special committee of costs that have been classified as O&M expenses, creates a situation that is conducive to overstating O&M expenses and understating construction costs that are subject to the Hard Cost Cap?

A. Yes. The Edwardsport expenditures and the project lists provided in testimony and discovery show that the vast majority of repairs and modifications and their costs are classified by Petitioner during the IGCC 12 and 13 review periods as O&M Expense rather than Construction Cost or O&M Capital. Moreover, the "default" O&M Expense amounts are apparently <u>not</u> reviewed by the Special Committee, which reviews only Capital projects. As the Company stated in its Response and Supplemental Response to CAC DR 10.2:

> [T]he Company holds meetings on a regular basis with a cross-functional team (including station, rates, legal, and accounting personnel) where each new capital project established for Edwardsport station is discussed and evaluated in the context of Item 2E of the Settlement Agreement and classified accordingly as an expenditure for ongoing capital maintenance or as an expenditure that should be subject to the Hard Cost Cap.

As a result, the vast majority of repairs and modifications and associated costs are never even reviewed by the Special Committee and their costs remain where they were initially charged "by default," i.e., in O&M Expense.

Q. Have the Joint Intevenors identified some costs that are of specific concern in terms of potential misclassification as O&M expenses rather than as construction costs?

A. Yes. The testimony of Joint Intervenors witness Schlissel discusses RSC slagging repairs and modifications as one illustrative example of "default" O&M expense which DEI executive and witness Thompson identified in Duke to GE Letter No. 1116 which should have been classified as Construction Costs under Settlement Section 2.E. Additionally, there are consequential repairs and modifications to other equipment which resulted from failures of Heat Trace and other Freeze Protection Equipment and to Liquid Nitrogen Pumps as additional examples of potentially misclassified "default" O&M Expense. Lending further to these concerns about cost misclassification, Petitioner's responses to discovery regarding repairs and modifications that have been classified as O&M Expense have been evasive. For example, even after the Commission's Order to Compel, Petitioner's response to CAC DR-18.28 and 29 says, "The Company does not use the referenced 'Work Orders or Funding Requests' for O&M expenditures." While it is correct that the Company does not use Capital Work Orders or Funding Requests for O&M expenditures, it does use O&M Work Orders for many if not most O&M expenditures.

As subsequently disclosed in Petitioner's responses to CAC DR Sets 22 and 25, the Company has a separate system for indexing O&M Work Orders called Maximo. Indeed, in its response to CAC-22.3, the Company provided Confidential Attachment 22.3-A in which it listed 23 specific Work Orders which had been identified by JIs from Edwardsport Shift Reports as being illustrative of those initiated during the IGCC-12 or 13 review periods. These 23 Work Orders were identified by number, description, name of requester(s), and calendar date of request. Then, in direct response to DR-22.4, the Company also provided the detailed costs for each of these same 23 Work Orders in Confidential Attachment 22.4-A.

Subsequently, in response to JIs request in CAC DR 25.2 for *all* O&M Expense Work Orders in Maximo initiated during the IGCC-12 and 13 review periods produced in the same formats as previously provided for those illustrative 23 Work Orders produced in response to DR-22.3 and 22.4, the Company produced a list of 3412 O&M Expense Work Orders representing over $14 million in O&M expense.

Q. Have you been able to review those 3412 O&M Expense Work Orders representing over $14 million in O&M expense for misclassified construction costs?

A. Not beyond a very limited basis. While these Work Orders were identified by number, description, name(s) of requester(s), and amount of expense, they also have a coded date of request so that JIs cannot match them up with the Shift Reports for the same calendar dates. However, a quick review of the descriptions for these O&M Expense Work Orders on just the first few of 298 pages certainly does attract one's attention and suggests, e.g., that Petitioner has been treating as O&M expenses repairs, replacements and other work relating to the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] It will take much longer than we currently have to get through the other pages to identify other items that may have been misclassified as O&M expenses rather than as construction costs during the IGCC-12 and 13 review periods. As illustrative further examples, a number attract attention just because of their dollar amounts and/or descriptions, e.g., [BEGIN

CONFIDENTIAL] [redacted]

[END CONFIDENTIAL]

Q. Are there potential cost misclassification concerns about at least some of the 19 O&M capital repair and modification projects that were identified by the Company after the Commission's Order to Compel?

A. Yes. Separately, in the very few (19) O&M Capital repair and modification projects which were identified by the Company (after the IURC Order to Compel) in response to Confidential Attachment 10.2-A and that you highlighted in your present e-mail, Joint Intervenors also question whether Petitioner has properly accounted for the cost of the following six specific projects (especially the first and third items):

[BEGIN CONFIDENTIAL]

[redacted]

[redacted].

[redacted]

[redacted]

[redacted]

[END CONFIDENTIAL]

Q. Do Petitioner's responses to CAC DRs 18.8 through 18.27, which related to follow up requests by Joint Intervenors about specific projects and Petitioner's accounting classification of their cost, provide specific reasons that the costs were not classified as construction costs?

A. No, the responses fail to provide specific reasons, but only state in identical words the Company's general view that each project does not meet the criteria for such classification. Petitioner's responses to CAC DRs 18.8 through 18.27, all of which related to follow up requests by Joint Intervenors about specific projects, were all quite vague in failing to provide specific reasons that the costs were not classified as construction costs, but instead only stated, over and over, verbatim, that each project does not meet the criteria for such classification.

Q. How should DEI be required to account for expenditures for construction costs that have been incurred during the IGCC-12 and 13 review periods for "repairs and modifications identified during start-up, testing, validation and commissioning as being necessary to reach 'final completion'"?

A. As provided for in the Settlement Agreement, DEI should be required to account for such costs as construction costs which are subject to the hard cost cap, and not as O&M expenses which are charged to Indiana ratepayers. As Joint Intervenors witness Schlissel explains, costs that were incurred by DEI for repairs and modifications identified during start-up, testing, validation and commissioning as being necessary to reach "final completion" include at least the following:

> (1) Costs for "repairs and modifications identified . . . as being necessary to reach 'final completion'" which the Company claims were identified during a time period on and after June 7, 2013 which the Company considered to be a period of "commercial operation" which should have been considered a period of further "testing." This category of improperly classified O&M expenses is, of course, inherent in the dispute between the Company and other parties regarding whether the period from June 7, 2013 through March 31, 2014 (or even later) should be considered a period of "commercial operation" or a period of further "testing" for Edwardsport. It is important to recognize that the implications of this dispute extend beyond the reclassification of *all* costs incurred *before* the appropriate "In Service Operation Date" to *some* costs incurred *after* that date.
>
> (2) Costs incurred on and after June 7, 2013 for "repairs and modifications identified during start-up, testing, validation and commissioning" prior to June 7, 2013 "as being necessary to reach 'final completion,'" which the Company has expensed currently since June 7, 2013. This category of improperly classified O&M expenses arises out of the manner in which non-capital costs are being reviewed and a concern that some are being classified as "Construction Costs" by the Company. DEI witness Stultz testified in both IGCC-12 (page 12, lines 18 to 21) and IGCC-13 (page 21, lines 4 to 9) that a team of Company employees meets on a regular basis "to review the maintenance needs of the Plant with an eye towards ensuring that no expenses are presented for recovery in this proceeding (or any other) that would contravene the Commission's Order in Cause No. 43114 IGCC 4S1." However, Joint Intervenors' follow up discovery shows that that this Duke review team is not reviewing all or even most of the maintenance activities and associated work orders initiated at the Plant, but only a comparatively limited number of requests for capital expenditures. Comparatively few requests are screened by the committee against a pre-determined "short list" of categories of repairs and modifications which the Company has apparently unilaterally decided meet the criteria set out in Section 5.E of the Settlement.

Q. Have you been able to quantify the impact on IGCC-12 and 13 costs claimed by the Company from this concern that construction costs were improperly classified by the Company as O&M expenses?

A. No. Joint Intervenors have experienced significant difficulty in obtaining the necessary documentation from the Company necessary to identify and quantify the two different categories of improperly classified O&M expenses. Indeed, most of the relevant information has been obtained only through follow up discovery requests and responses after the Commission granted Joint Intervenors' Motion to Compel involving initial requests included in CAC Discovery Request Sets 6 and 10.

Q. Could these misclassified costs be significant in amount?

A. Yes. As explained in the testimony of Joint Intervenors witness Schlissel, these misclassified costs exist and are believed to be significant in amount. As an example, there are numerous maintenance work orders the costs of which are included in the O&M costs which the Company is seeking to recover in IGCC-12 and 13 which are at least arguably traceable to design and construction issues identified as requiring correction prior to the Company's in-service declaration of June 7, 2013, especially but not exclusively in the gasification and grey water processes of the Plant.

Q. What is your recommendation concerning these potentially improperly classified O&M expenses?

A. I recommend that the Commission order DEI to make a compliance filing based on a systematic review of costs incurred since June 7, 2013, which have "defaulted" to O&M expense and that identifies those costs in the categories listed above that DEI recorded as O&M expenses during the IGCC-12 and 13 periods, and require DEI to justify its treatment of such costs as O&M expenses, and for the Commission to order DEI to remove from IGCC 12 and 13 O&M expenses any such costs which are determined to have been misclassified, and to record them as construction costs that are subject to the Hard Cost Cap. In addition, I recommend that the non-Duke parties have an opportunity to review and submit responses to the Company's compliance filing, with a hearing being held to address any unresolved differences among the parties.

Q. Does this issue of cost misclassification appear to be a continuing concern that will be continuing beyond the IGCC 12 and 13 review periods?

A. Yes. I recommend that the Commission order DEI to identify in Edwardsport IGCC proceedings beyond IGCC-13 costs which are in these categories and should thus be capitalized as construction costs that are subject to the Hard Cost Cap and not recorded as O&M expense for accounting purposes, and to provide sufficient supporting documentation of its accounting decisions to enable review by non-DEI parties and by the Commission of the Company's accounting for Edwardsport costs.

VIII. COMMISSION ORDERED REFUND AND CARRYING COSTS ON RATEPAYER MONIES BEING HELD BY THE COMPANY

Q. Has the Commission ordered a refund of monies DEI collected from ratepayers related to the "Deferred Tax Incentive"?

A. Yes. In IGCC-4S1, the Commission granted one of the exceptions raised by the Joint Intervenors, which was to disallow the collection of the revenues associated with the Cost Control Incentive (aka the Deferred Tax Incentive). This Incentive had been made subject to refund in the Commission's IGCC-4 Interim Order from August 2010 through December 2012. Page 151 of Duke's 2012 SEC form 10-K indicated that the actual amount through 2012 is approximately $31 million:

> The IURC modified the settlement agreement as previously agreed to by the parties to (i) require the Duke Energy Indiana to credit customers $31 million for cost control incentive payments which the IURC found to be unwarranted as a result of delays that arose from project cost overruns …

Petitioner's response to discovery request CAC 5.9 in IGCC-10[18] shows that Petitioner has calculated the Regulatory Liability amount for such ratepayer-provided funds to be $30,731,789 through December 31, 2012.[19] The Commission's Order in IGCC-10 (p. 27) required that this amount be addressed in IGCC-11:

> As to Joint Intervenors' request to require the Company to provide a credit to customers in this proceeding related to the deferred tax incentive and to include interest on such credit, we note that in the IGCC-4S1 Order, Duke was directed to net the deferred income tax incentive regulatory liability against the regulatory asset created by the IGCC-9 rate mitigation effort. That rate mitigation effort sought to avoid depreciation and O&M costs from being included in the rates proposed for IGCC-9 by deferring any such costs being included for recovery until the next IGCC rider filing after IGCC-10. We note that the rates proposed in this filing include forecasted depreciation and O&M costs. In effect, the IGCC-9 rate mitigation effort did not impact the rates proposed in IGCC-l0 and the language of the 2012 Settlement suggests that IGCC-11 would be the time when the recovery of the IGCC-9 rate mitigation effort would commence. Accordingly, it would be appropriate to include the regulatory liability and offsetting IGCC-9 rate mitigation asset, to the extent there is one, in the development of revenue requirements and rates in IGCC-11.

Q. How did Petitioner treat the Regulatory Liability amount for such ratepayer-provided funds of $30,731,789 through December 31, 2012 in IGCC-11?

A. In its IGCC-11 filing, Petitioner reflected this Regulatory Liability amount for such ratepayer-provided funds of $30,731,789 through December 31, 2012 only as an amortization amount of $5,121,965, which Petitioner credited against its claimed revenue requirement. Specifically, Petitioner witness Douglas proposed to begin amortizing the $30,731,789 in IGCC-11, and reflected one-sixth of that amount as a

[18] This was attached to my IGCC-11 Direct Testimony as Exhibit LA-2.

[19] Petitioner's response to CAC 5.9 did not include a monthly breakout of the accumulation of the $30,731,789. The same information is also contained in Petitioner witness Douglas' IGCC-11 Supplemental Testimony Workpaper 27, page 1, as shown in Exhibit LA-7 attached to my IGCC-11 Direct Testimony, which also shows how Petitioner calculated the $30,731,789, but similarly without a monthly breakout.

reduction to its IGCC-11 revenue requirement on Exhibit D-2, in the amount of $5,121,965.

Q. How has Petitioner treated the Regulatory Liability amount for such ratepayer-provided funds of $30,731,789 through December 31, 2012 in its IGCC-12 filing?

A. In its IGCC-12 filing, as shown on Workpaper 8A, Petitioner reflected this Regulatory Liability amount for such ratepayer-provided funds of $30,731,789 through December 31, 2012 only as an amortization amount of $5,121,965, which Petitioner credited against the other components of its claimed IGCC-12 revenue requirement, as shown on Petitioner's Exhibit C-2, page 5 of 11, line 14.

Q. Was Petitioner's proposal to continue to hold these ratepayer funds, without any provision for interest or financing costs, challenged in IGCC-11?

A. Yes. Joint Intervenors challenged Petitioner's proposal to continue to hold these ratepayer funds, without interest or financing costs, in IGCC-11. As described in my Direct Testimony in IGCC-11 at pages 9-19, the Company has been holding funds in the principal amount of approximately $31 million, which the Commission ruled over a year ago belonged to its customers. The Company began to collect this money from its customers more than three years ago. So, the primary concern is that customers derive a current benefit from their funds, either in the form of a refund or a credit against current rates and charges.

The secondary concern is that the Company is continuing to hold these customer funds without accruing interest on them. As described in my Direct Testimony in IGCC-11, I have been advised by counsel for Joint Intervenors that this is patently unlawful because the Indiana Supreme Court has previously ruled that such funds are “money had and received” under Indiana law and legally required to accrue interest from the date of collection at the statutory rate of eight percent.

Q. What do you recommend concerning these ratepayer funds?

A. Consistent with my Direct Testimony and the Joint Intervenor legal pleadings in IGCC-11 concerning this issue:

(1) The Commission should direct the Company to accrue simple interest at the statutory rate of eight percent (8%) per annum from the date of collection on the $30,731,789 Cost Control Incentive (aka Deferred Tax Incentive) revenues collected from approximately July 29, 2010 through the next applicable billing cycle in which the Commission ordered refund can be fully returned to customers.

(2) The Commission should direct the Company to credit the $30,731,789 in Cost Control Incentive (aka Deferred Tax Incentive) revenues collected against the revenue requirement in the combined IGCC-12 and 13 review proceeding, rather than allowing the Company to continue to hold onto this ratepayer money for three full years without interest as its witness Douglas has proposed in her Supplemental Direct Testimony. As I had noted in my IGCC-11 testimony, this could be accomplished by the Commission in its IGCC-11 Order by therein ordering the Company to replace the $5,121,965 amount for the Petitioner-proposed one-sixth amortization of the Cost Control Incentive on Petitioner's Exhibit D-5, page 4 of 9, line 14, with the full $30,731,789 Cost Control Incentive amount plus simple interest at the statutory rate of 8% for the period during which Petitioner has held such ratepayer money.

(3) If the full refund of these ratepayer monies is ordered in IGCC-11, then the amortization amounts proposed by the Company in Ms. Douglas' exhibits in IGCC-12 and 13 (as well as IGCC-11) should be eliminated.

IX. THE NEED FOR ADDITIONAL PROCEEDINGS

Q. In the testimony which you earlier prefiled on April 2, 2014 in Cause No. 43114-IGCC-12 but have now withdrawn and replaced with this testimony in consolidated Cause Nos. 43114-IGCC-12 & 13, you recommended that the Commission initiate a special investigation of Edwardsport and/or a general rate case for Duke Energy Indiana. Do you renew that recommendation in this testimony?

A. I am advised by counsel for Joint Intervenors that it remains my clients' legal position that the Edwardsport IGCC should be determined by the Commission in a general rate case for Duke Energy Indiana to be "used and useful" within the meaning of Ind. Code § 8-1-2-6 prior to authorizing the recovery through rates under Ind. Code § 8-1-8.8-1 et seq. of the post in-service operating costs of Edwardsport, notwithstanding the Commission's ruling to the contrary in its Docket Entry of June 10, 2014. It also remains my professional opinion that sound regulatory policy requires that the post in-service operating costs of a baseload generating plant of the size and cost of Edwardsport be authorized for recovery through customer rates only after the Commission has determined the plant to be both "in service" and "reasonably necessary for the provision of utility service" in a general rate case for the utility which owns 100% of the plant. So, this testimony of mine should not be construed to withdraw, abandon or waive those positions for purposes of any subsequent appeal which my clients may take of a Commission final order in this consolidated Cause premised on the June 10, 2014 Docket Entry.

But, this testimony of mine does not rely on the legal and policy positions earlier taken by my clients and me regarding the necessity for a "used and useful" determination within the meaning of Ind. Code § 8-1-2-6 by the Commission in a general rate case. Instead, my testimony relies on the overwhelming evidence and conclusions included in the testimony of Joint Intervenors' witness Schlissel that Edwardsport has not been in "commercial operation" but instead has been in "testing" for the entire IGCC-12 and 13 review periods, including the period of June 7, 2013 through March 31, 2014 and thus none of its costs during that period may properly be characterized as "reasonable and necessary" operating costs within the meaning of Ind. Code § 8-1-8.8-1 et seq. Instead, they should be characterized as construction costs subject to the "hard cost cap" approved by the Commission in Cause No. 43114-IGGC-4S1. Alternatively, should the Commission conclude that Edwardsport has been in "commercial operation" for some or all of the period between June 7, 2013 and March 31, 2014, my testimony is based on the overwhelming evidence cited and conclusions reached by Mr. Schlissel and myself that the costs during that period have been excessive in significant part and thus not "reasonable and necessary" within the meaning of Ind. Code § 8-1-8.8-1 et seq.

As a result, my recommendation in this consolidated cause is that the costs incurred for Edwardsport from June 7, 2013 through March 31, 2014 should be disallowed, in whole or in significant part, for purposes of recovery from customers through Rider 61 without the need for a Duke Energy Indiana general rate case or a further special investigation of Edwardsport. Moreover, as indicated previously, it is my recommendation that the Commission issue an order in IGCC-12 and 13 directing that DEI make a Compliance Filing to address the Commission findings and conclusions in that order and providing the non-Duke parties with the opportunity to file subsequently testimony and exhibits responsive to the DEI Compliance filing, to be followed by a further hearing and order by the Commission.

X. CONCLUSION

Q. Does this conclude your direct testimony at this time?

A. Yes, it does. However, I am reserving the right to revise or supplement this testimony as additional, supplemental and revised responses to discovery are received by Joint Intervenors.

VERIFICATION

I, Ralph C. Smith, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

Ralph C. Smith   December 15, 2014

Ralph C. Smith   Date

EXHIBIT LA-1

Exhibit LA-1

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102 T E-1032-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)

Docket No. 2003-34	Sidney Telephone Company (Maine PUC)
Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
U-06-134	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0083	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, IHnc. (Arizona CC)
E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-111049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL-FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)

Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)
12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)
Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
Formal Case No. 1103	Potomac Electric Power Company (District of Columbia PSC)
U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
12-2881-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 3 (Ohio PUC)
Docket No. 36989	Georgia Power Company (Georgia PSC)
Cause No. 43114-IGCC-11	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
UM 1633	Investigation into Treatment of Pension Costs in Utility Rates (Oregon PUC)
13-1892-EL FAC	Financial Audit of the FAC and AER of the Ohio Power Company – Audit I (Ohio PUC)
E-04230A-14-0011 & E-01933A-14-0011	Reorganization of UNS Energy Corporation with Fortis, Inc. (Arizona CC)
14-255-EL RDR	Regulatory Compliance Audit of the 2013 DIR of Ohio Power Company (Ohio PUC)
U-14-001	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
U-14-002	Alaska Power Company (The Regulatory Commission of Alaska)
PUE-2014-00026	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
Formal Case No. 1119	Merger of Exelon Corporation, Pepco Holdings, Inc., Potomac Electric Power Company, Exelon Energy Delivery Company, LLC, and New Special Purpose Entity, LLC (District of Columbia PSC)
R-2014-2428742	West Penn Power Company (Pennsylvania PUC)
R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
R-2014-2428745	Metropolitan Edison Company (Pennsylvania PUC)

EXHIBIT LA-2

COPY

FILED
APR 3 0 2012
INDIANA UTILITY REGULATORY COMMISSION

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. (1) SEEKING APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IC 8-1-8.5 AND 8-1-8.7; (2) AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPLICABLE RELATED COSTS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IC 8-1-8.8-11 AND -12 , (3) ESTABLISHMENT OF A SUBDOCKET PROCEEDING TO REVIEW THE COST ESTIMATE FOR THE IGCC PROJECT; AND (4) APPROVAL OF A REQUEST TO UPDATE ITS DEPRECIATION RATES FOR PRODUCTION TRANSMISSION, DISTRIBUTION AND GENERAL PLANT AND EQUIPMENT	)	**CAUSE NO. 43114-IGCC4S1**

VERIFIED JOINT PETITION TO REOPEN THE RECORDS IN THIS CAUSE FOR THE PURPOSE OF TAKING ADDITIONAL EVIDENCE RELATING TO A SETTLEMENT AGREEMENT REACHED BY LESS THAN ALL PARTIES AND <u>SUBMISSION OF SUCH SETTLEMENT AGREEMENT</u>

Duke Energy Indiana, Inc. ("Duke Energy Indiana"), Nucor Steel-Indiana, a division of Nucor Corporation ("Nucor"), the Duke Energy Indiana Industrial Group ("Industrial Group"), and the Indiana Office of the Utility Consumer Counselor (the "OUCC") (collectively referred to herein as "Settling Parties"), pursuant to 170 IAC 1-1.1-17 and 170 IAC 1-1.1-22, respectfully petition the Commission to reopen the records in Phase I and Phase II of this proceeding to allow for the taking of additional evidence: specifically, the Settlement Agreement reached in this

("Project" or "IGCC Project"). The Settling Parties desire to fully settle all disputes, claims, and issues among them arising out of or relating to these proceedings and the construction of the Project, now and in the future,[2] and do so, among other reasons, to avoid the continued time and expense of further proceedings and the inherent uncertainties and potential outcomes associated with such proceedings. The Settling Parties agree, solely for purposes of this Settlement, that the Construction Costs included in the Hard Cost Cap (plus Additional AFUDC) (as such terms are defined below) are reasonable and necessary and should not be reduced because of any claims of imprudence, fraud, concealment, or gross mismanagement, or related claims. The Settling Parties agree that the record in this proceeding includes substantial evidence that this Settlement is reasonable and will result in just and reasonable rates for Duke Energy Indiana's customers. The Settling Parties further agree that this Settlement is a reasonable compromise and that each Settling Party that filed testimony previously in this Cause will file testimony with the IURC in support of this Settlement, and in such testimony, each such party will explain to the IURC how, in that Settling Party's view, the Settlement is just and reasonable and in the public interest, based on substantial evidence of record.

The Settling Parties agree to work together to achieve approval of this Settlement by July 1, 2012.

2. Hard Cost Cap.

A. The Settling Parties agree that the Construction Costs (defined later in this Section 2) of the Project shall be subject to a "Hard Cost Cap" of $2.595 billion as of June 30, 2012,[3] for all Indiana ratemaking purposes (base rate cases and rider proceedings) ("the Hard Cost Cap Project Costs").

B. The Settling Parties agree that, until the Hard Cost Cap Project Costs are fully reflected in Duke Energy Indiana's electric rates, Duke Energy Indiana shall be allowed to accrue and recover actual AFUDC (or post-in-service AFUDC, whichever is applicable) on the portion of the $2.595 billion that has not been reflected in such rates. From and after July 1, 2012, Duke Energy Indiana shall recover actual AFUDC on the Hard Cost Cap Project Costs as follows: until November 30, 2012, 100% of the AFUDC and thereafter, 85% of the AFUDC incurred after such date ("the Additional AFUDC"). Retail AFUDC on the Hard Cost Cap Project Costs is currently accruing at approximately $9 million per month. There will be no cost recovery from retail electric customers above the retail amounts included in the $2.595 billion Hard Cost Cap, other than the Additional AFUDC as provided for above, and any force majeure events as defined below.

[2] Except as specifically provided for in this Settlement.

[3] Reflecting approximately $2.319 billion in direct costs on a total Company basis and approximately $276 million in retail jurisdictional (only) AFUDC as of June 30, 2012. The retail jurisdictional portion of these direct costs is approximately $2.129 billion.

C. The Settling Parties agree that, except for ongoing additions, replacements, and maintenance capital expenditures made separate and apart from and not included in Construction Costs, in future retail electric base rate cases and riders, the portion of revenue requirements attributable to a return on the Project shall equal the original cost of the Project, defined as the Hard Cost Cap Project Costs, including the Additional AFUDC as provided for above, less accumulated depreciation, multiplied by Duke Energy Indiana's authorized weighted cost of capital calculated on an original cost basis.

D. The Settling Parties agree that the IURC should modify the Certificates of Public Convenience and Necessity ("CPCNs") for the IGCC Project to reflect an approved Project cost estimate equal to the Hard Cost Cap Project Costs ($2.595 billion as of June 30, 2012) plus Additional AFUDC that accrues on that amount on and after July 1, 2012, as described above. Other than as set forth in this Settlement, the Non-Duke Settling Parties agree that they will seek no further rate or regulatory "penalties" relative to the construction and overall final Construction Costs of the Project (plus AFUDC as allowed above); however, the non-Duke Settling Parties shall retain all rights under Indiana law to make arguments and seek relief concerning post-in-service operating performance of the Project.

E. "Construction Costs" of the Project shall be defined in accordance with usual utility practices and in accordance with FERC guidelines and includes all costs required to achieve "final completion," as that term is defined in the December 20, 2007 contract between Duke Energy Indiana and GE (see Attachment A), such as engineering, materials, construction and equipment purchases, capitalized AFUDC (through June 30, 2012), and all start-up and testing, validation and commissioning costs, and costs of repairs and modifications identified during start-up, testing, validation and commissioning and all such costs required whether actually disbursed or only obligated during such period, as well as any costs subsequently incurred to pay claims disallowed or unpaid during such period; except that: "Construction Costs" of the Project and the Hard Cost Cap shall not include normal operating and maintenance ("O&M") expenditures on the Project, which, according to FERC guidelines, begin after the "In-Service Operational Date" and shall not include subsequent ongoing capital spent on the Project for normal capitalized repairs or maintenance expenditures or additional plant and equipment necessary for the continued operation of the Project after the "In-Service Operational Date", unless identified during start-up, testing, validation and commissioning as being necessary to reach "final completion", nor does the cap apply to orders of the Commission approving cost recovery related to carbon capture and storage (including study costs) involving the Project.

F. "In-Service Operational Date" means the first date by which the Project has both (1) been declared in-service in accordance with FERC guidelines as the earlier of the date the asset is placed in operation or is ready for service; and (2) has operated on both natural gas and syngas; provided however that the In-Service Operational Date shall not be prior to September 24, 2012.

G. The Hard Cost Cap Project Costs and Additional AFUDC may only be increased due to an increase in prudently incurred construction costs for the Project caused by a force majeure event beyond the control and without the fault or negligence of Duke Energy Indiana or its suppliers or contractors involved in the Project, such as, by way of example, the following: acts of God, the public enemy, or any governmental or military entity.

3. **IGCC Rider Implementation.**

In recognition of some uncertainty as to the actual In-Service Operational Date of the Project and in effort to restart the IGCC Rider in a reasonable manner, the Settling Parties agree as follows:

As part of the approval of this Settlement, the IGCC Construction Work In Progress ("CWIP") Rider (Standard Contract Rider No. 61) will be approved to allow CWIP recovery to begin immediately on and up to the Hard Cost Cap Project Costs, and any Additional AFUDC as provided for in Section 2. In the event this Settlement is approved prior to approval of the IGCC-8 CWIP Rider proceeding, then CWIP recovery shall begin on Construction Costs amounts approved through the IGCC-6 CWIP Rider (which are less than the Hard Cost Cap), and recovery of CWIP for Construction Costs amounts over the IGCC-6 CWIP Rider amount (up to the Hard Cost Cap Project Costs and Additional AFUDC) will begin upon approval of the IGCC-8 CWIP Rider proceeding (expected in the September/October 2012 timeframe).

The Settling Parties agree that in IGCC-9 (to be filed in approximately May 2012), Duke Energy Indiana's proposed tariffs will not include costs of post-in-service Project depreciation or O&M costs (or property taxes) for inclusion in the IGCC-9 Rider (other than operating costs for items that have been included in previous Rider filings). Thus, the IGCC-9 filing will reflect financing costs (CWIP), but no post-in-service depreciation or O&M costs (or property taxes). Rather, in IGCC-10 (to be filed in approximately November 2012), Duke Energy Indiana will begin recovering post-in-service Project depreciation and O&M costs (and property tax expenses) on a projected basis for a six-month period. Duke Energy Indiana will defer the actual depreciation and O&M costs (and property tax expenses) incurred for all months from the In-Service Operational Date until the effective date of IGCC-10 rates. At the time of the next IGCC Rider filing (or general base rate case filing) after the filing of IGCC-10, Duke Energy Indiana will recover the deferred amount (without carrying costs) over a three-year period either through the IGCC Rider or through inclusion in base retail electric rates.

4. **Retail Electric Rate Case Moratorium.**

Except in the case of an emergency pursuant to Ind. Code § 8-1-8-113, Duke Energy Indiana agrees that it will not file for an increase in its basic rates and charges for retail electric service prior to March 2013, and that no increase to its basic rates and charges for retail electric service as a result of a final order in a retail electric base rate case filing shall be implemented

Attachment A
Cause No. 43144-IGCC4S1 Settlement

"**Final Completion**" shall be deemed to have occurred upon the satisfaction of all of the following conditions:

(a) Substantial Completion shall have occurred;

(b) the performance of the Work shall be one hundred percent (100%) complete (other than Work that by its nature cannot be completed until after Final Completion (e.g., warranty Work)), including the Punch List Work and delivery of all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract;

(c) either (i) the Equipment shall have satisfied all Performance Guarantees or (ii) the Seller shall have paid to the Buyer all liquidated damages for failure to satisfy the LD Performance Guarantees as required by Section 2.9;

(d) there shall exist no Event of Default and no event which, with the passage of time or the giving of notice or both, would be an Event of Default; and

(e) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.

"**Substantial Completion**" shall be deemed to have occurred upon the satisfaction of all of the following conditions:

(a) Delivery of all GEP Equipment shall have occurred;

(b) the performance of the Work shall be complete (other than Work that by its nature cannot be completed until after Substantial Completion (e.g., warranty Work)), with the exception of the Punch List;

(c) the Facility shall have satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees;

(d) the Seller shall have delivered to the Buyer all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract, with the exception of the Punch List;

(e) the Seller shall have provided all training required by Exhibit S, with the exception of the Punch List; and

(f) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.

EXHIBIT LA-3

IURC Cause No. 43114 IGCC-8
Data Request Set No. 4
Received: March 13, 2012
CAC 4.4

Request:

Please explain in detail the operational relationship, if any, between the "initial start-up and generation of test power for sale" from CTG-1 and CTG-2 referenced in the subject Notification in Joint Intervenors Data Request 4.3 and the classification or declaration by the Company of all or part of the Edwardsport plant as "in service" for accounting and ratemaking purposes.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant and not calculated to lead to the discovery of relevant or admissible information in this proceeding. The IGCC-8 proceeding provides a progress report for ongoing review of construction of the Edwardsport Project as it proceeds and seeks cost recovery for the April – September 2011 time frame. Any request for information outside of that six month period is both irrelevant and outside the scope of this proceeding.

Response:

Subject to and without waiving the foregoing general and specific objections, Duke Energy Indiana states as follows: The "initial start-up and generation of test power for sale" occurs while the plant is still in test phase, which is earlier than when the plant will be declared as in-service for accounting and ratemaking purposes. The plant will be declared in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.

Witness: Diana L. Douglas

IURC Cause No. 43114 IGCC-8
Data Request Set No. 4
Received: March 13, 2012
CAC 4.5

Request:

Please identify the event(s) and date(s) on which the Company currently plans to classify or declare all or part of the Edwardsport plant as "in service" for accounting and ratemaking purposes.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant and not calculated to lead to the discovery of relevant or admissible information in this proceeding. The IGCC-8 proceeding provides a progress report for ongoing review of construction of the Edwardsport Project as it proceeds and seeks cost recovery for the April – September 2011 time frame. Any request for information outside of that six month period is both irrelevant and outside the scope of this proceeding.

Response:

Subject to and without waiving the foregoing specific and general objections, Duke Energy Indiana states as follows: The plant will be declared in-service for accounting and ratemaking purposes once testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.

Witness: Diana L. Douglas

IURC Cause No. 43114 IGCC-8
Data Request Set No. 4
Received: March 13, 2012
CAC 4.6

Request:

Please identify by issuing agency or organization, title, number and effective date the rule(s) or regulation(s) on which the Company expects to rely for purposes of classifying or declaring all or part of the Edwardsport plant as "in service" for accounting and ratemaking purposes.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant and not calculated to lead to the discovery of relevant or admissible information in this proceeding. The IGCC-8 proceeding provides a progress report for ongoing review of construction of the Edwardsport Project as it proceeds and seeks cost recovery for the April – September 2011 time frame. Any request for information outside of that six month period is both irrelevant and outside the scope of this proceeding.

Response:

Subject to and without waiving the foregoing specific and general objections, Duke Energy Indiana states as follows: The Company will be following the FERC's guidance in Electric Plant Instructions 3 and 9 and in Accounting Release AR-5, "Capitalization of Allowance for Funds Used During Construction" as well as the FASB's guidance in Accounting Standards Codification section 360-10-30-1, "Property, Plant, and Equipment – Overall – Initial Measurement – General – Historical Cost Including Interest."

Witness: Diana L. Douglas

IURC Cause No. 43114 IGCC-8
Data Request Set No. 4
Received: March 13, 2012
CAC 4.7

Request:

Please identify by receiving agency, title and form number any notice to a federal, state or local agency of government which the Company expects to provide the classification or declaration of all or part of the Edwardsport plant as "in service" for accounting and ratemaking purposes.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant and not calculated to lead to the discovery of relevant or admissible information in this proceeding. The IGCC-8 proceeding provides a progress report for ongoing review of construction of the Edwardsport Project as it proceeds and seeks cost recovery for the April – September 2011 time frame. Any request for documents outside of that six month period is both irrelevant and outside the scope of this proceeding.

Response:

Subject to and without waving the foregoing specific and general objections, Duke Energy Indiana states as follows: Upon completion of the test period and declaration of the plant as in-service, the Company will be notifying FERC in accordance with Electric Plant Instruction 9.D, which is required due to the testing period extending beyond a period of 90 days.
In addition, the Company will notify the IURC when the IGCC Project has been declared "in service" for accounting and ratemaking purposes as part of the Company's ongoing review filings in the IGCC Rider proceedings.

Witness: Diana L. Douglas

EXHIBIT LA-4

DEI-IG
IURC Cause No. 43114 IGCC-12
Data Request Set No. 1
Received: May 12, 2014

SUPPLEMENTAL RESPONSE 8-11-14
SUPPLEMENTAL INFORMATION IN BOLD
DEI-IG 1.4

Request:

In the Settlement Agreement in IURC Cause No. 43114 IGCC4S1 Phase I and Phase II, dated April 30, 2012 (the "Settlement Agreement"), In-Service Operational Date is defined to mean "the first date by which the [Edwardsport IGCC Project (the "Project")] has both (1) been declared in-service in accordance with FERC guidelines as the earlier of the date the asset is placed in operation or is ready for service; and (2) has operated on both natural gas and syngas…."

a. Please provide a narrative explanation of how the date Duke declared the Project to be in service, June 7, 2013, complies with the above definition in the Settlement Agreement.

b. Please provide a description of the referenced FERC guidelines.

c. Please provide a copy of the referenced FERC guidelines.

d. Please describe Duke's understanding and provide Duke's definition of the term "placed in operation" and describe how the Project met this requirement on June 7, 2013.

e. Please describe Duke's understanding and provide Duke's definition of the term "ready for service" and describe how the Project met this requirement on June 7. 2013.

Objection:

Duke Energy Indiana objects to this Request to the extent it seeks Duke Energy Indiana to provide definitions of or describe certain terms in the Settlement Agreement. Under Indiana law, the Settlement Agreement speaks for itself and interpreting it should be done within the four corners of the Agreement. Duke Energy Indiana also objects to subpart (b) of this Request seeking Duke Energy Indiana to "describe" the referenced FERC guidelines, which also speak for themselves.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Please see the direct testimony of Mr. Stultz in IGCC-11 at 4:17–5:6 and in IGCC-12 at 3:9–3:20. Please also see the affidavit of Mr. Wiles, filed in this proceeding on April 4, 2014.

After discussion with Counsel for DEI-IG, Duke Energy Indiana is providing the following supplemental response: The definition of "In-Service Operational Date" has three subparts, and provides that it "means the first date by which the Project" has met the requirements of those subparts.

(1) first, Edwardsport must be "declared in-service in accordance with FERC guidelines as the earlier of the date the asset is placed in operation or is ready for service." The relevant FERC guidelines include the following:

> **"Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as Electric Plant in Service and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service…." FERC Electric Plant Instruction 3.A.(17)(b)**
>
> **"The equipment accounts shall include the necessary costs of testing or running a plant or parts thereof during an experimental or test period prior to such plant becoming ready for or placed in service…" FERC Electric Plant Instruction 9.D.**
>
> **"The cost of efficiency or other tests made subsequent to the date equipment becomes available for service shall be charged to the appropriate expense accounts, except that tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase may be charged to the appropriate electric plant account." FERC Electric Plant Instruction 9.E.**

> **"Capitalization of AFUDC stops when the facilities have been tested and are placed in, or ready for, service. This would include those portions of construction projects completed and put into service although the project is not fully completed." FERC Accounting Release No. 5 ("AR-5")**

This accounting guidance provides utilities with a fair amount of discretion in making determinations about when to place an asset in service and stop capitalization of AFUDC. The determination of a commercial in-service date, therefore, is subject to the interpretation of a utility's accounting and operating personnel. For example, AR-5 specifically contemplates "portions of construction projects completed and put into service although the project is not fully completed." Under this guidance, it was possible that Duke Energy Indiana could have determined that the power block portion of Edwardsport was in service when the CTs were operating on natural gas and still have been in accordance with FERC accounting guidelines. Similarly, the gasifiers could have been placed in service once they were lit off and began operating and still have been considered in accordance with FERC accounting guidelines.

AR-5 also provides that capitalization of AFUDC stops when "the facilities have been tested and are placed in, or ready for, service." The guidance allows for facilities to be determined in service merely when they are "ready for service," not actually in operation. The definition of In-Service Operational Date in the Settlement Agreement is consistent with this accounting guidance, stating the in-service operational date is to be the "<u>earlier</u> of the date the asset is placed in operation or is ready for service." Therefore, once Edwardsport was "ready for service," not necessarily operating, an in-service determination would have complied with both the FERC accounting guidelines and the terms of the Settlement Agreement.

However, Duke Energy Indiana conservatively interpreted this guidance in the Settlement Agreement by imposing upon itself additional steps that had to occur before the Company would consider Edwardsport in-service. It outlined those milestones in the settlement rebuttal testimony of Mr. Womack: "the in-service date is expected to occur after key project milestones are complete – specifically, after the Project has been tested and validated on syngas, as well as natural gas. The Project schedule provides for this validation to occur on an instrumented rotor on Combustion Turbine Unit 1 and then for that rotor to be removed and replaced with a permanent rotor." Duke Energy Indiana did not declare Edwardsport in-service until after those milestones had occurred, even though one interpretation of the FERC accounting guidance and the terms of the Settlement Agreement might find that the facilities had been "ready for service" for many months prior to June 7, 2013, and potentially even could have been "placed in service" prior to that date given the operations of the plant. From October 30, 2012 through May 2013, the

gasifiers operated over 900 hours. The CTs operated over 6,400 hours on both natural gas and syngas from March 30, 2012 through May 2013.

(2) Second, Edwardsport must have "operated on both natural gas and syngas" prior to a declaration of in-service.

This was an additional test imposed by the Settlement Agreement (to which Duke Energy Indiana agreed) that prevented Duke Energy Indiana from declaring the power block in-service to operate on natural gas only (the CTs were started up and operated on natural gas before the gasifiers were started up and syngas produced). The power block was, in fact, placed in service for income tax purposes under income tax regulation prior to the remainder of the plant being placed in service. Duke Energy Indiana complied with this portion of the Settlement Agreement definition because it operated Edwardsport on both natural gas and syngas prior to declaring the plant in-service. As mentioned above, the CTs operated over 6,400 hours from March 30, 2012 through May 2013 on both natural gas and syngas that was produced from the gasifiers.

(3) Third, Edwardsport could not be declared in-service prior to September 24, 2012. Duke Energy Indiana complied with this portion of the definition by declaring the plant in-service June 7, 2013, clearly after September 24, 2012.

b. See response to subpart (a) above.

c. Please see the affidavit of Mr. Wiles, filed in this proceeding on April 4, 2014. The relevant guidelines are included therein. See also the Company's response to subpart (a) above.

d. and e. See above Objection. **See also the Company's prior response to subpart (a) above.**

EXHIBIT LA-5

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act

Electric Plant Instructions

3. *Components of construction cost.*

A. For Major utilities, the cost of construction properly includible in the electric plant accounts shall include, where applicable, the direct and overhead cost as listed and defined hereunder:

(1) *Contract work* includes amounts paid for work performed under contract by other companies, firms, or individuals, costs incident to the award of such contracts, and the inspection of such work.

(2) *Labor* includes the pay and expenses of employees of the utility engaged on construction work, and related workmen's compensation insurance, payroll taxes and similar items of expense. It does not include the pay and expenses of employees which are distributed to construction through clearing accounts nor the pay and expenses included in other items hereunder.

(3) *Materials and supplies* includes the purchase price at the point of free delivery plus customs duties, excise taxes, the cost of inspection, loading and transportation, the related stores expenses, and the cost of fabricated materials from the utility's shop. In determining the cost of materials and supplies used for construction, proper allowance shall be made for unused materials and supplies, for materials recovered from temporary structures used in performing the work involved, and for discounts allowed and realized in the purchase of materials and supplies.

Note: The cost of individual items of equipment of small value (for example, $500 or less) or of short life, including small portable tools and implements, shall not be charged to utility plant accounts unless the correctness of the accounting therefor is verified by current inventories. The cost shall be charged to the appropriate operating expense or clearing accounts, according to the use of such items, or, if such items are consumed directly in construction work, the cost shall be included as part of the cost of the construction

(4) *Transportation* includes the cost of transporting employees, materials and supplies, tools, purchased equipment, and other work equipment (when not under own power) to and from points of construction. It includes amounts paid to others as well as the cost of operating the utility's own transportation equipment. (See item 5 following.)

(5) *Special machine service* includes the cost of labor (optional), materials and supplies, depreciation, and other expenses incurred in the maintenance, operation and use of special machines, such as steam shovels, pile drivers, derricks, ditchers, scrapers, material unloaders, and other labor saving machines; also expenditures for rental, maintenance and operation of machines of others. It does not include the cost of small tools and other individual items of small value or short life which are included in the cost of materials and supplies. (See item 3, above.) When a particular construction job requires the use for an extended period of time of special machines, transportation or other equipment, the net book cost thereof, less the appraised or salvage value at time of release from the job, shall be included in the cost of construction.

(6) *Shop service* includes the proportion of the expense of the utility's shop department assignable to construction work except that the cost of fabricated materials from the utility's shop shall be included in *materials and supplies.*

(7) *Protection* includes the cost of protecting the utility's property from fire or other casualties and the cost of preventing damages to others, or to the property of others, including payments for discovery or extinguishment of fires, cost of apprehending and prosecuting incendiaries, witness fees in relation thereto, amounts paid to municipalities and others for fire protection, and other analogous items of expenditures in connection with construction work.

(8) *Injuries and damages* includes expenditures or losses in connection with construction work on account of injuries to persons and damages to the property of others; also the cost of investigation of and defense against actions for such injuries and damages. Insurance recovered or recoverable on account of compensation paid for injuries to persons incident to construction shall be credited to the account or accounts to which such compensation is charged Insurance recovered or recoverable on account of property damages incident to construction shall be credited to the account or accounts charged with the cost of the damages.

(9) *Privileges and permits* includes payments for and expenses incurred in securing temporary privileges, permits or rights in connection with construction work, such as for the use of private or public property, streets, or highways, but it does not include rents, or amounts chargeable as franchises and consents for which see account 302, Franchises and Consents.

(10) *Rents* includes amounts paid for the use of construction quarters and office space occupied by construction forces and amounts properly includible in construction costs for such facilities jointly used.

(11) *Engineering and supervision* includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

(12) *General administration capitalized* includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

(13) *Engineering services* includes amounts paid to other companies, firms, or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

(14) *Insurance* includes premiums paid or amounts provided or reserved as self-insurance for the protection against loss and damages in connection with construction, by fire or other casualty injuries to or death of persons other than employees, damages to property of others, defalcation of employees and agents, and the nonperformance of contractual obligations of others. It does not include workmen's compensation or similar insurance on employees included as *labor* in item 2, above.

(15) *Law expenditures* includes the general law expenditures incurred in connection with construction and the court and legal costs directly related thereto, other than law expenses included in protection, item 7, and in injuries and damages, item 8.

(16) *Taxes* includes taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service.

(17) *Allowance for funds used during construction* (Major and Nonmajor Utilities) includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

(a) The formula and elements for the computation of the allowance for funds used during construction shall be:

$A_i = s(S/W) + d(D/D+P+C)(1-S/W)$

$A_e = [1-S/W][p(P/D+P+C)+c(C/D+P+C)]$

A_i=Gross allowance for borrowed funds used during construction rate.

A_e=Allowance for other funds used during construction rate.

S=Average short-term debt.

s=Short-term debt interest rate.

D=Long-term debt.

d=Long-term debt interest rate.

P=Preferred stock.

p=Preferred stock cost rate.

C=Common equity.

c=Common equity cost rate.

W= Average balance in construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment and fabrication, less asset retirement costs (See General Instruction 25) related to plant under construction.

(b) The rates shall be determined annually. The balances for long-term debt, preferred stock and common equity shall be the actual book balances as of the end of the prior year. The cost rates for long-term debt and preferred stock shall be the weighted average cost determined in the manner indicated in §35.13 of the Commission's Regulations Under the Federal Power Act. The cost rate for common equity shall be the rate granted common equity in the last rate proceeding before the ratemaking body having primary rate jurisdictions. If such cost rate is not available, the average rate actually earned during the preceding three years shall be used. The short-term debt balances and related cost and the average balance for construction work in progress plus nuclear fuel in process of refinement, conversion, enrichment, and fabrication shall be estimated for the current year with appropriate adjustments as actual data becomes available.

Note: When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation or ready for service, shall be treated as*Electric Plant in Service* and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

(18) *Earnings and expenses during construction.* The earnings and expenses during construction shall constitute a component of construction costs.

(a) The earnings shall include revenues received or earned for power produced by generating plants during the construction period and sold or used by the utility. Where such power is sold to an independent purchaser before intermingling with power generated by other plants, the credit shall consist of the selling price of the energy. Where the power generated by a plant under construction is delivered to the utility's electric system for distribution and sale, or is delivered to an associated company, or is delivered to and used by the utility for purposes other than distribution and sale (for manufacturing or industrial use, for example), the credit shall be the fair value of the energy so delivered. The revenues shall also include rentals for lands, buildings etc., and miscellaneous receipts not properly includible in other accounts.

(b) The expenses shall consist of the cost of operating the power plant, and other costs incident to the production and delivery of the power for which construction is credited under paragraph (a), above, including the cost of repairs and other expenses of operating and maintaining lands, buildings, and other property, and other miscellaneous and like expenses not properly includible in other accounts.

(19) *Training costs* (Major and Nonmajor Utilities). When it is necessary that employees be trained to operate or maintain plant facilities that are being constructed and such facilities are not conventional in nature, or are new to the company's operations, these costs may be capitalized as a component of construction cost. Once plant is placed in service, the capitalization of training costs shall cease and subsequent training costs shall be expensed. (See Operating Expense Instruction 4.)

(20) *Studies* includes the costs of studies such as nuclear operational, safety, or seismic studies or environmental studies mandated by regulatory bodies relative to plant under construction. Studies relative to facilities in service shall be charged to account 183, Preliminary Survey and Investigation Charges.

(21) *Asset retirement costs.* The costs recognized as a result of asset retirement obligations incurred during the construction and testing of utility plant shall constitute a component of construction costs.

B. For Nonmajor utilities, the cost of construction of property chargeable to the electric plant accounts shall include, where applicable, the cost of labor; materials and supplies; transportation; work done by others for the utility; injuries and damages incurred in construction work; privileges and permits; special machine service; allowance for funds used during construction, not to exceed without prior approval of the Commission, amounts computed in accordance with the formula prescribed in paragraph (a) of paragraph (17) of this Instruction; training costs; and such portion of general engineering, administrative salaries and expenses, insurance, taxes, and other analogous items as may be properly includable in construction costs. (See Operating Expense Instruction 4.) The rates and balances of short and long-term debt, preferred stock, common equity and construction work in progress shall be determined as prescribed in paragraph (b) of paragraph (17) of this Instruction.

EXHIBIT LA-6

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act

Electric Plant Instructions

4. *Overhead Construction Costs.*

A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

B. As far as practicable, the determination of pay roll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

C. For Major utilities, the records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each electric plant account, and the bases of distribution of such costs.

EXHIBIT LA-7

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act

Electric Plant Instructions

9. *Equipment.*

D. The equipment accounts shall include the necessary costs of testing or running a plant or parts thereof during an experimental or test period prior to such plant becoming ready for or placed in service. In the case of Nonmajor utilities, the utility shall pay the fee prescribed in part 381 of this chapter and shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 30 days. In the case of Major utilities, the utility shall furnish the Commission with full particulars of and justification for any test or experimental run extending beyond a period of 120 days for nuclear plant, and a period of 90 days for all other plant. Such particulars shall include a detailed operational and downtime log showing days of production, gross kilowatts generated by hourly increments, types, and periods of outages by hours with explanation thereof, beginning with the first date the equipment was either tested or synchronized on the line to the end of the test period.

EXHIBIT LA-8

Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act

Electric Plant Instructions

9. *Equipment.*

E. The cost of efficiency or other tests made subsequent to the date equipment becomes available for service shall be charged to the appropriate expense accounts, except that tests to determine whether equipment meets the specifications and requirements as to efficiency, performance, etc., guaranteed by manufacturers, made after operations have commenced and within the period specified in the agreement or contract of purchase may be charged to the appropriate electric plant account.

EXHIBIT LA-9

FEDERAL ENERGY REGULATORY COMMISSION
Washington, D.C. 20426

In Reply Refer To:
Office of Enforcement
Docket No. AI11-1-000
February 16, 2011

TO ALL JURISDICTIONAL NATURAL GAS PIPELINE COMPANIES AND PUBLIC UTILITIES AND LICENSEES

Subject: Revision to Accounting Release No. 5, Capitalization of Allowance for Funds Used During Construction

The Commission has historically relied on the guidance issued by the Commission's Chief Accountant in Accounting Release No. 5 (Revised) (AR-5),[1] Capitalization of Interest During Construction, to address when a company may begin to accrue an allowance for funds used during construction (AFUDC).[2] Under this guidance, a natural gas pipeline company was allowed to accrue AFUDC beginning with the date it filed an application for a certificate of public convenience and necessity (certificate) with the Commission, provided that it incurred construction costs on a continuous, planned progressive basis.

The natural gas industry has undergone substantial changes since the issuance of AR-5 in 1968. Today, many natural gas pipeline companies seeking to construct pipeline facilities participate in the pre-filing process instituted by the Commission in 2001.[3] For

---

[1] *Accounting Release No. 5 (Revised), Capitalization of Interest During Construction*, effective January 1, 1968, FERC Stats. & Regs. ¶ 40,005.

[2] AR-5 uses the term "interest during construction" which is now referred to as AFUDC and as such we will use the term AFUDC in place of "interest during construction" in the revised AR-5.

[3] In 2001, the Commission instituted an optional pre-filing process and encouraged entities seeking authorization to construct new facilities to prepare and submit to the Commission conceptual design and engineering features of the proposed project, as well as extensive information about potential environmental, security and safety impacts prior to filing a certificate application. *See* Office of Energy Projects Gas Outreach Team, *Ideas for Better Stakeholder Involvement in the Interstate Natural Gas Pipeline Planning Pre-Filing Process*, December 2001, *available at* http://www.ferc.gov/legal/maj-ord-reg/land-docs/stakeholder.pdf.

the past ten years, natural gas pipeline companies participating in the pre-filing process have typically incurred significant project-related costs prior to filing a certificate application with the Commission. These changes required the Commission to reconsider its longstanding policy of limiting AFUDC accruals generally to those costs incurred on the date a certificate application was filed with the Commission.

On March 18, 2010, the Commission revised its policy for accruing AFUDC in *Southern Natural* and *Florida Gas*.[4] In these orders, the Commission concluded that the certificate application date was no longer an appropriate milestone for determining when to begin the accrual of AFUDC since many natural gas pipeline companies have been participating in the pre-filing process and have incurred significant project-related costs prior to filing a certificate application with the Commission.

The Commission found that it is important that the revised AFUDC policy achieve the following objectives: (a) be in harmony with the recent developments in the natural gas industry; (b) allow AFUDC capitalization on all prudent construction costs; (c) serve to promote infrastructure development by allowing for recovery of all monies invested in the construction of facilities; and (d) be directly correlated to the occurrence of construction project-related costs incurred to prepare the construction project for its intended use.

Based on the above objectives, the Commission revised its AFUDC accrual policy to allow natural gas pipeline companies to begin accruing AFUDC on construction projects when the following two conditions are met: (1) capital expenditures for the project have been incurred; and (2) activities that are necessary to get the construction project ready for its intended use are in progress (AFUDC policy conditions). The Commission explained that the term “activities” is to be construed broadly and includes all the actions, excluding preliminary survey and investigation activities, required to prepare the construction project for its intended use. In addition, the Commission found that the date that the Commission approves the request to initiate the pre-filing process is a strong indicator of the initiation of construction project-related activities.[5]

The Commission also directed applicants seeking a certificate for authorization to construct pipeline facilities to make a representation in their filing that AFUDC accruals included in the cost of the facilities are calculated in accordance with the Commission’s

---

[4] *Southern Natural Gas Co.*, 130 FERC ¶ 61,193 (2010) (*Southern Natural*); *Florida Gas Transmission Co. LLC*, 130 FERC ¶ 61,194 (2010) (*Florida Gas*).

[5] To accrue AFUDC prior or subsequent to the initiation of pre-filing, natural gas pipelines must be prepared to demonstrate that the AFUDC policy conditions have been met. *E.g., Southern Natural*, 130 FERC ¶ 61,193 at P 36, 39; *Florida Gas* 130 FERC ¶ 61,194 at P 25, 28.

rules and regulations and pursuant to and consistent with the AFUDC policy conditions. Finally, the Commission emphasized that natural gas pipeline companies must retain records supporting the commencement of AFUDC accruals, and such AFUDC accruals will be subject to scrutiny through Commission audit or rate review, just as any other cost would.

Although the Commission established the revised AFUDC accrual policy in the context of when natural gas pipeline companies may begin AFUDC accruals, the revised policy is comparable with that currently used by public utilities and licensees. As a result, this revised AR-5 shall apply to all entities under the Commission's jurisdiction to which AFUDC is applicable. This revision will provide for consistency and uniformity in determining AFUDC.

Natural gas pipeline companies and public utilities and licensees may continue to accrue AFUDC for as long as the two conditions in the revised AFUDC policy continue to be met. However, AFUDC accruals must cease once the facility being constructed has been tested and is ready for, or placed in, service. This includes those portions of construction projects completed and put into service although the project is not fully completed. Finally, if construction is interrupted or suspended, AFUDC accruals must cease unless the company can justify the interruption as being reasonable under the circumstances.

The Commission delegated authority to act on this matter to the Director of the Office of Enforcement or his designee under 18 C.F.R. § 375.311 (2010). The Director has designated this authority to the Chief Accountant. This letter constitutes final agency action. Your company may file a request for rehearing with the Commission within 30 days of the date of this order under 18 C.F.R. § 385.713 (2010).

Sincerely,

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement

Enclosure

FEDERAL ENERGY REGULATORY COMMISSION

ACCOUNTING RELEASE NUMBER 5 (AR-5) (Revised)

Capitalization of Allowance for Funds Used During Construction

Question:

What is the proper period for capitalization of Allowance for Funds Used During Construction (AFUDC)?

Answer:

The capitalization period for AFUDC shall begin when two conditions are present: (1) capital expenditures for the project have been incurred; and (2) activities that are necessary to get the construction project ready for its intended use are in progress. AFUDC capitalization shall continue as long as these two conditions are present.

The term “activities” is to be construed broadly and includes all the actions required to prepare the construction project for its intended use, including activities prior to physical construction, such as the development of plans or the process of obtaining permits from governmental authorities. However, the term “activities” does not include preliminary survey and investigation activities. Activities occurring prior to the above two conditions being met would be considered preliminary in nature for the purpose of determining feasibility of projects under contemplation and would be included in Accounts 183, Preliminary Survey and Investigation Charges, or 183.2, Other Preliminary Survey and Investigation Charges, as appropriate. These preliminary activities would not be subject to AFUDC accruals until such a time as the two conditions are met and the amounts included in Account 183 or Account 183.2 are transferred to Account 107, Construction Work in Progress.

No AFUDC should be accrued during periods of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances.

Capitalization of AFUDC stops when the facilities have been tested and are placed in, or ready for, service. This would include those portions of construction projects completed and put into service although the project is not fully completed. Should the test period exceed the allowable 30, 90, or 120 days, the company must submit full particulars and justification for an extension of such period to the Commission in accordance with Electric and Gas Plant Instruction 9(D) in the Uniform System of Accounts.

Bryan K. Craig
Director and Chief Accountant
Division of Audits
Office of Enforcement

Effective: March 18, 2010

Document Content(s)

AI11-1-000.DOC..1-5

EXHIBIT LA-10

360-10-30 Initial Measurement

General

> Historical Cost Including Interest

30-1

Paragraph 835-20-05-1 states that the historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. As indicated in that paragraph, if an asset requires a period of time in which to carry out the activities necessary to bring it to that condition and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset.

30-2

See the glossary for a definition of **activities** necessary to bring an asset to the condition and location necessary for its intended use.

> Acquisition of the Residual Value in Leased Assets

30-3

An interest in the residual value of a leased asset recognized under paragraph 360-10-25-4 shall be measured initially at the amount of cash disbursed, the fair value of other consideration given, and the present value of liabilities assumed.

30-4

The fair value of the interest in the residual value of the leased asset at the date of the agreement shall be used to measure its cost if that fair value is more clearly evident than the fair value of assets surrendered, services rendered, or liabilities assumed.

586

> Other Asset Acquisition Concepts

30-5

The following paragraphs contain links to other Subtopics that contain guidance on acquiring property, plant, and equipment under other concepts. The following may not represent a complete list of other locations containing property, plant, and equipment acquisition guidance.

> > Business Combinations

30-6

See Section 805-20-25 for general guidance related to assets acquired in a business combination.

> > Accounting for Nonmonetary Transactions

30-7

See paragraphs 845-10-30-1 through 30-10 for guidance related to assets acquired in a nonmonetary exchange.

> > Accounting for Leases

30-8

See SubTopic 840-30 for guidance related to assets acquired under a capital lease.

EXHIBIT LA-11

DEI-IG
IURC Cause No. 43114 IGCC-11
Data Request Set No. 1
Received: September 20, 2013

DEI-IG 1.4

Request:

Please provide the following:

a. For each rate class, and for all classes combined as an average, the increase in rates that the requested $63,187,853 in O&M expenses would cause if approved.
b. For each rate class, and for all classes combined as an average, the increase in rates that Duke would have requested had the O&M expenses requested been the amount reflected in Duke's settlement testimony in IGCC 4S1.
c. How large of an increase, above that reflected in Duke's IGCC 4S1 testimony, is Duke seeking in this IGCC 11 proceeding?

Objection:

Duke Energy Indiana objects to this Request as purporting to seek a study or analysis Duke Energy Indiana has not performed and to which it objects performing. Duke Energy Indiana also objects to this Request as vague and ambiguous, particularly the phrases "increase in rates" and "large of an increase" without further explanation.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Please see the above objection.
b. Please see the above objection.
c. Please see the above objection. In the spirit of cooperation, please also see Attachment DEI-IG 1.4-A. Answering further, please note that Duke Energy Indiana's IGCC 4S1 testimony was intended to show the value of the Hard Cost Cap and other rate mitigation terms in the Settlement Agreement, and was not an updated estimate for all items included in the rider. As noted on Petitioner's Exhibit III-2, which was filed with Kent K. Freeman's testimony in Cause No. 43114 IGCC 4S1, the source for the starting amounts was Petitioner's Exhibit WW-1, which was filed in Cause No. 43114 IGCC 4S1 on March 10, 2011.

Exhibit LA-11
Cause Nos. 43114-IGCC-12/13
Page 2 of 10

Attachment DEI-IG 1.4-A

DUKE ENERGY INDIANA

Estimated and Actual Retail Revenue
Requirement For the IGCC Project Based
On the April 30, 2012 Settlement Agreement
(Dollars in Thousands)

Line No.	Description	Factor	Retail $3.0B Cost Estimate (1)	Retail Adjustment Per Settlement (2)	Adjusted Retail Per Settlement	Actual IGCC 11 (4)	Variance Actual IGCC 11 To Settlement
		(A)	(B)	(C)	(D)	(E)	(F)
1	Return on OCD Investment		$ 276,238	$ (58,792)	$ 217,446	$ 244,700	$ 27,254
2	Estimated O&M	1.02130	42,505	-	42,505	69,992	27,487
3	Depreciation Expense		105,136	(13,867)	91,269	111,648	20,379
4	Estimated O&M and Depreciation		147,641	(13,867)	133,774	181,640	47,866
	Taxes Excluding Federal and State Income						
5	New Property Tax Expense	1.02130	28	-	28	510	482
6	State Tax Credit	1.11631	(15,370)	-	(15,370)	(15,204)	166
7	Federal Tax Credit (3)	1.63767	(4,347)	-	(4,347)	-	4,347
8	Total Taxes Excluding Federal and State		(19,689)	-	(19,689)	(14,694)	4,995
9	By-Product Sales	1.02130	(937)	-	(937)	-	937
10	Reconciliation and Rate HLF Credit		-	-	-	(4,083)	(4,083)
11	Credit for Edwardsport Expenses	1.02130	(5,396)	-	(5,396)	(5,396)	-
12	Total Revenue Requirement		397,857	(72,659)	325,198	402,167	76,969
13	Depreciation Expense Credit (Retail Amount)		-	(35,176)	(35,176)	(35,175)	1
14	Total Retail Revenue Requirement		$ 397,857	$ (107,835)	$ 290,022	$ 366,992	$ 76,970

Notes: (1) Per Petitioner's Redacted Exhibit WW-1 adjusted for an IGCC Project Cost of $3.0 Billion.
(2) Per Petitioner's Redacted Exhibit WW-1 adjusted for the Hard Cost Cap and other rate mitigation measures. Actual amounts will be updated based on current rates of return and revenue conversion factors.
(3) Timing of federal tax credit is dependent on the Company's net operating loss position which is impacted by the federal bonus tax depreciation that will benefit retail customers.
(4) Per IGCC-11 filing.

DUKE ENERGY INDIANA

Estimated and Actual Retail Revenue
Requirement For the IGCC Project Based
On the April 30, 2012 Settlement Agreement
(Dollars in Thousands)

Line No.	Description	Retail Allocation Percentage (1)	Actual Retail Revenues For Twelve Months Ended June 30, 2013	Retail Impact: $3.0 B Cost Estimate (2)	Retail Impact: Impact of Settlement (3)	Retail Impact: Per Settlement	Actual IGCC 11 (4)	Variance Actual IGCC 11 To Settlement
		(A)	(B)	(C)	(D)	(E)	(F)	(G)
	By Rate Group							
1	RS	36.727%	$ 955,924	$ 146,122	$ (39,607)	$ 106,515	$ 135,009	$ 28,494
2	CS	5.206%	114,669	20,712	(5,613)	15,099	19,137	4,038
3	LLF	14.583%	381,072	58,019	(15,725)	42,294	53,607	11,313
4	HLF	41.987%	818,335	167,048	(45,276)	121,772	153,761	31,989
5	Other	1.497%	96,808	5,956	(1,614)	4,342	5,478	1,136
6	Total	100.000%	$ 2,366,808	$ 397,857	$ (107,835)	$ 290,022	$ 366,992	$ 76,970
	Percentage Rate Increase By Rate Group							
7	RS			15.3%	-4.2%	11.1%	14.1%	3.0%
8	CS			18.1%	-4.9%	13.2%	16.7%	3.5%
9	LLF			15.2%	-4.1%	11.1%	14.1%	3.0%
10	HLF			20.4%	-5.5%	14.9%	18.8%	3.9%
11	Other			6.2%	-1.7%	4.5%	5.7%	1.2%
12	Total			16.8%	-4.5%	12.3%	15.5%	3.2%

Notes: (1) Per the cost of service study approved by the Commission in Cause No. 42359.
(2) Per Petitioner's Redacted Exhibit WW-1 adjusted for an IGCC Project Cost of $3.0 Billion.
(3) Per Petitioner's Redacted Exhibit WW-1 adjusted for the Hard Cost Cap and other rate mitigation measures.
Actual amounts will be updated based on current rates of return and revenue conversion factors.
(4) Per IGCC-11 filing.

DEI-IG
IURC Cause No. 43114 IGCC-11
Data Request Set No. 2
Received: October 17, 2013

DEI-IG 2.7

Request:

Refer to Duke's testimony in Cause 43114 ("original case"). Please provide the following information:

a. Duke's estimate for O&M expenses in the original case.

b. Identify where in the original case Duke states its estimate for the amount of O&M expense.

c. Identify where in the original case Duke itemizes the costs included in its O&M expense estimate.

d. How much employee labor and expenses were included in Duke's estimate for O&M expenses in the original case?

e. How much contract labor and expenses were included in Duke's estimate for O&M expenses in the original case?

f. How much expense for materials and supplies was included in Duke's estimate for O&M expenses in the original case?

g. How much expense for outages was included in Duke's estimate for O&M expenses in the original case?

h. How much plant administrative costs and overheads were included in Duke's estimate for O&M expenses in the original case?

i. How much property taxes were included in Duke's estimate for O&M expenses in the original case?

j. How much other types of costs were included in Duke's estimate for O&M expenses in the original case? Identify each type of cost.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is not reasonably calculated to lead to admissible evidence in this proceeding. O&M estimates used in a regulatory proceeding seven years ago are not relevant to the estimated O&M used in the IGCC-11 proceeding. Duke Energy Indiana further objects to subparts (b) and (c) as seeking Duke Energy Indiana to "identify where" certain estimates were stated, which DEI-IG could just as easily do itself. Duke Energy Indiana also objects to this Request on the grounds that it seeks Duke Energy Indiana to perform a study or compilation that it has not performed and to which it objects performing. Duke Energy Indiana objects to this Request on the grounds that "estimate for O&M expenses" and "O&M expense estimate" is vague and ambiguous.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana states as follows:

a. In Cause No. 43114, $44,132,000 was the estimate of O&M for 2013 before converting to revenue requirements and applying the retail jurisdictional allocation percentage. This estimate assumed 100% ownership of the plant and was used for modeling purposes. The associated retail jurisdictional revenue requirements amount included in the rate impact calculations in Cause No. 43114 was $41,372,000 for 2013.
b. Please see Confidential Petitioner's Exhibit No. 28-E, Page 6 of 15, in Cause No. 43114.
c. Please see Confidential Petitioner's Exhibit No. 28-E, Page 6 of 15, in Cause No. 43114.
d. See the Company's prior response to DEI-IG 2.4.
e. See the Company's prior response to DEI-IG 2.4
f. See the Company's prior response to DEI-IG 2.4
g. See the Company's prior response to DEI-IG 2.4
h. See the Company's prior response to DEI-IG 2.4
i. In Cause No. 43114, property taxes were not included in O&M expenses, but were included as a separate line item in the amount of $1,261,000 for 2013. The retail jurisdictional revenue requirements in Cause No. 43114 associated with property taxes for 2013 was $1,182,000.
j. Retail jurisdictional revenue requirements for variable O&M for 2013: $15,777,000
   Retail jurisdictional revenue requirements for fixed O&M for 2013: $25,595,000

Exhibit LA-11
Cause Nos. 43114-IGCC-12/13
Page 6 of 10

IG-CX-5

CONFIDENTIAL NOT FOR PUBLIC ACCESS

Petitioners' Exhibit No. 28-E
Page 6 Of 15

Duke Energy Indiana, Inc.

Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)

(Dollars In Thousands)

Row	Description	Assumptions	Factor (d)	July 2008	January 2009	July 2009	January 2010	July 2010	January 2011	July 2011	January 2012	July 2012	January 2013	July 2013	January 2014	July 2014	January 2015
8	RETURN ON INVESTMENT																
9	Return on Equity (ROE)		[redacted]														
10	Weighted Average Cost Of Capital	(a)															
12	Cumulative Project Expenditures At																
13	CWIP Cut-Off Date																
14	Less: Accumulated Depreciation																
15	Less: Accumulated Deferred Income Taxes																
17	Net IGCC Investment Subject To																
18	CWIP Ratemaking																
20	Assumed Percentage Ownership																
21	Net IGCC Investment Applicable To DEI																
23	Return on OCD Investment																
25	Est. Revenue Requirement Before Jurisdictional Allocation																
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis																
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																
30	Variable O&M																
31	Fixed O&M																
32	Amortization of Plan Presentation Costs																
33	Emission Allowance Savings																
34	Fuel Savings																
35	Est. O&M Expenses Before Jurisdictional Allocation			150	-	150	-	-	-	-	21,601	21,600	22,066	22,066	22,564	22,562	23,071
37	Depreciation Exp. Incl. Net Negative Salvage		[redacted]														
39	Total Operating Expense Excl. Taxes																
41	Revenue Requirement Applicable to O&M and Depreciation Expense																
43	TAXES EXCLUDING FEDERAL & STATE INCOME																
44	Property Taxes																
45	Less: TIF Savings																
46	Less: Property Tax Abatement																
47	Net Property Tax Expense																
49	State Tax Credit	(f)															
51	Federal Investment Tax Credit	(g)															
52	Ratable Flow through of Credit																
53	Effective at 100% Basis Reduction																
54	Net Credit																
56	Total Taxes Excl. Fed. & State Income Taxes																
58	Revenue Requirement Applicable to Taxes																
60	REVENUE FROM SALE OF BYPRODUCTS																
61	Revenue Requirement Applicable to Byproduct Sales																
63	Revenue Requirement Prior to Edwardsport Credit																
65	Less: Credit for Edwardsport Operating Expenses Included in Rates																
67	Rev Requirement Applicable to Edwardsport Credit																
69	Total Revenue Requirement Before Jurisdictional Allocation																
70	Retail Allocation Factor	0.															
71	Total Retail Revenue Requirement																

CONFIDENTIAL NOT FOR PUBLIC ACCESS

	A	B	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
1	Duke Energy Indiana, Inc.																	
2																		
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)																	
4																		
5	(Dollars In Thousands)																	
6																		
7		Assumption	July 2015	January 2016	July 2016	January 2017	July 2017	January 2018	July 2018	January 2019	July 2019	January 2020	July 2020	January 2021	July 2021	January 2022	July 2022	January 2023
8	RETURN ON INVESTMENT																	
9	Return on Equity (ROE)																	
10	Weighted Average Cost Of Capital	(a)																
11																		
12	Cumulative Project Expenditures At		[redacted]															
13	CWIP Cut-Off Date																	
14	Less: Accumulated Depreciation																	
15	Less: Accumulated Deferred Income Taxes																	
16																		
17	Net IGCC Investment Subject To																	
18	CWIP Ratemaking																	
19																		
20	Assumed Percentage Ownership																	
21	Net IGCC Investment Applicable To DEI																	
22																		
23	Return on OCD Investment																	
24																		
25	Est. Revenue Requirement Before Jurisdictional Allocation																	
26																		
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis																	
28																		
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																	
30	Variable O&M																	
31	Fixed O&M																	
32	Amortization of Plan Presentation Costs																	
33	Emission Allowance Savings																	
34	Fuel Savings																	
35	Est. O&M Expenses Before Jurisdictional Allocation		23,070	23,612	23,610	24,121	24,120	24,663	24,662	25,218	25,218	25,809	25,809	26,366	26,365	26,959	26,958	27,566
36																		
37	Depreciation Exp. Incl. Net Negative Salvage		[redacted]															
38																		
39	Total Operating Expense Excl. Taxes																	
40																		
41	Revenue Requirement Applicable to O&M and Depreciation Expense																	
42																		
43	TAXES EXCLUDING FEDERAL & STATE INCOME																	
44	Property Taxes																	
45	Less: TIF Savings																	
46	Less: Property Tax Abatement																	
47	Net Property Tax Expense																	
48																		
49	State Tax Credit	(f)																
50																		
51	Federal Investment Tax Credit	(g)																
52	Ratable Flow through of Credit																	
53	Effective at 100% Basis Reduction																	
54	Net Credit																	
55																		
56	Total Taxes Excl. Fed. & State Income Taxes																	
57																		
58	Revenue Requirement Applicable to Taxes																	
59																		
60	REVENUE FROM SALE OF BYPRODUCTS																	
61	Revenue Requirement Applicable to Byproduct Sales																	
62																		
63	Revenue Requirement Prior to Edwardsport Credit																	
64																		
65	Less: Credit for Edwardsport Operating Expenses Included in Rates																	
66																		
67	Rev Requirement Applicable to Edwardsport Credit																	
68																		
69	Total Revenue Requirement Before Jurisdictional Allocation																	
70	Retail Allocation Factor																	
71	Total Retail Revenue Requirement																	

CONFIDENTIAL NOT FOR PUBLIC ACCESS

Petitioners' Exhibit No. 28-E
Page 8 Of 15

	A	B	AJ	AK	AL	AM	AN	AO	AP	AQ	AR	AS	AT	AU	AV	AW	AX	AY
1	Duke Energy Indiana, Inc.																	
2																		
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)																	
4																		
5	(Dollars In Thousands)																	
6			July	January	July	January	July	January	July	January	July	January	July	January	July	January	July	January
7		Assumption	2023	2024	2024	2025	2025	2026	2026	2027	2027	2028	2028	2029	2029	2030	2030	2031
8	RETURN ON INVESTMENT																	
9	Return on Equity (ROE)																	
10	Weighted Average Cost Of Capital	(a)																
11																		
12	Cumulative Project Expenditures At		[redacted]															
13	CWIP Cut-Off Date																	
14	Less: Accumulated Depreciation																	
15	Less: Accumulated Deferred Income Taxes																	
16																		
17	Net IGCC Investment Subject To																	
18	CWIP Ratemaking																	
19																		
20	Assumed Percentage Ownership																	
21	Net IGCC Investment Applicable To DEI																	
22																		
23	Return on OCD Investment																	
24																		
25	Est. Revenue Requirement Before Jurisdictional Allocation																	
26																		
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis																	
28																		
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																	
30	Variable O&M																	
31	Fixed O&M																	
32	Amortization of Plan Presentation Costs																	
33	Emission Allowance Savings																	
34	Fuel Savings																	
35	Est. O&M Expenses Before Jurisdictional Allocation		27,565	28,212	28,211	28,820	28,819	29,469	29,467	30,132	30,130	30,838	30,837	31,532	31,531	32,242	32,240	32,967
36			[redacted]															
37	Depreciation Exp. Incl. Net Negative Salvage																	
38																		
39	Total Operating Expense Excl. Taxes																	
40																		
41	Revenue Requirement Applicable to O&M and Depreciation Expense																	
42																		
43	TAXES EXCLUDING FEDERAL & STATE INCOME																	
44	Property Taxes																	
45	Less: TIF Savings																	
46	Less: Property Tax Abatement																	
47	Net Property Tax Expense																	
48																		
49	State Tax Credit	(f)																
50																		
51	Federal Investment Tax Credit	(g)																
52	Ratable Flow through of Credit																	
53	Effective at 100% Basis Reduction																	
54	Net Credit																	
55																		
56	Total Taxes Excl. Fed. & State Income Taxes																	
57																		
58	Revenue Requirement Applicable to Taxes																	
59																		
60	REVENUE FROM SALE OF BYPRODUCTS																	
61	Revenue Requirement Applicable to Byproduct Sales																	
62																		
63	Revenue Requirement Prior to Edwardsport Credit																	
64																		
65	Less: Credit for Edwardsport Operating Expenses Included in Rates																	
66																		
67	Rev Requirement Applicable to Edwardsport Credit																	
68																		
69	Total Revenue Requirement Before Jurisdictional Allocation																	
70	Retail Allocation Factor																	
71	Total Retail Revenue Requirement																	

Exhibit LA-11
Cause Nos. 43114-IGCC-12/13
Page 9 of 10

CONFIDENTIAL NOT FOR PUBLIC ACCESS

Petitioners' Exhibit No. 28-E
Page 9 Of 15

	A	B	AZ	BA	BB	BC	BD	BE	BF	BG	BH	BI	BJ	BK	BL	BM	BN	BO
1	Duke Energy Indiana, Inc.																	
2																		
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)																	
4																		
5	(Dollars In Thousands)																	
6																		
7		Assumption	July 2031	January 2032	July 2032	January 2033	July 2033	January 2034	July 2034	January 2035	July 2035	January 2036	July 2036	January 2037	July 2037	January 2038	July 2038	January 2039
8	RETURN ON INVESTMENT																	
9	Return on Equity (ROE)																	
10	Weighted Average Cost Of Capital	(a)	[redacted]															
11																		
12	Cumulative Project Expenditures At																	
13	CWIP Cut-Off Date																	
14	Less: Accumulated Depreciation																	
15	Less: Accumulated Deferred Income Taxes																	
16																		
17	Net IGCC Investment Subject To																	
18	CWIP Ratemaking																	
19																		
20	Assumed Percentage Ownership																	
21	Net IGCC Investment Applicable To DEI																	
22																		
23	Return on OCD Investment																	
24																		
25	Est. Revenue Requirement Before Jurisdictional Allocation																	
26																		
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis																	
28																		
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES																	
30	Variable O&M																	
31	Fixed O&M																	
32	Amortization of Plan Presentation Costs																	
33	Emission Allowance Savings																	
34	Fuel Savings																	
35	Est. O&M Expenses Before Jurisdictional Allocation		32,965	33,708	33,708	34,467	34,466	35,242	35,241	36,036	36,034	36,846	36,845	37,675	37,674	38,522	38,521	39,389
36																		
37	Depreciation Exp. Incl. Net Negative Salvage		[redacted]															
38																		
39	Total Operating Expense Excl. Taxes																	
40																		
41	Revenue Requirement Applicable to O&M and Depreciation Expense																	
42																		
43	TAXES EXCLUDING FEDERAL & STATE INCOME																	
44	Property Taxes																	
45	Less: TIF Savings																	
46	Less: Property Tax Abatement																	
47	Net Property Tax Expense																	
48																		
49	State Tax Credit	(f)																
50																		
51	Federal Investment Tax Credit	(g)																
52	Ratable Flow through of Credit																	
53	Effective at 100% Basis Reduction																	
54	Net Credit																	
55																		
56	Total Taxes Excl. Fed. & State Income Taxes																	
57																		
58	Revenue Requirement Applicable to Taxes																	
59																		
60	REVENUE FROM SALE OF BYPRODUCTS																	
61	Revenue Requirement Applicable to Byproduct Sales																	
62																		
63	Revenue Requirement Prior to Edwardsport Credit	$																
64																		
65	Less: Credit for Edwardsport Operating Expenses Included in Rates																	
66																		
67	Rev Requirement Applicable to Edwardsport Credit																	
68																		
69	Total Revenue Requirement Before Jurisdictional Allocation	$																
70	Retail Allocation Factor																	
71	Total Retail Revenue Requirement	$																

CONFIDENTIAL NOT FOR PUBLIC ACCESS

	A	B	BP	BQ	BR	BS	BT
1	Duke Energy Indiana, Inc.						
2							
3	Estimated Retail Revenue Requirement Applicable To The Edwardsport IGCC Facility (100% Ownership)						
4							
5	(Dollars In Thousands)						
6							
7		Assumption	July 2039	January 2040	July 2040	January 2041	July 2041
8	RETURN ON INVESTMENT						
9	Return on Equity (ROE)						
10	Weighted Average Cost Of Capital	(a)					
11							
12	Cumulative Project Expenditures At		[redacted]				
13	CWIP Cut-Off Date						
14	Less: Accumulated Depreciation						
15	Less: Accumulated Deferred Income Taxes						
16							
17	Net IGCC Investment Subject To						
18	CWIP Ratemaking						
19							
20	Assumed Percentage Ownership						
21	Net IGCC Investment Applicable To DEI						
22							
23	Return on OCD Investment						
24							
25	Est. Revenue Requirement Before Jurisdictional Allocation						
26							
27	Est. Revenue Requirement Before Jurisdictional Allocation on 6-Months Basis						
28							
29	ESTIMATED OPERATING EXPENSES EXCLUDING FUEL & EMISSION ALLOWANCES						
30	Variable O&M						
31	Fixed O&M						
32	Amortization of Plan Presentation Costs						
33	Emission Allowance Savings						
34	Fuel Savings						
35	Est. O&M Expenses Before Jurisdictional Allocation		39,388	40,275	40,274	41,182	41,180
36							
37	Depreciation Exp. Incl. Net Negative Salvage		[redacted]				
38							
39	Total Operating Expense Excl. Taxes						
40							
41	Revenue Requirement Applicable to O&M and Depreciation Expense						
42							
43	TAXES EXCLUDING FEDERAL & STATE INCOME						
44	Property Taxes						
45	Less: TIF Savings						
46	Less: Property Tax Abatement						
47	Net Property Tax Expense						
48							
49	State Tax Credit	(f)					
50							
51	Federal Investment Tax Credit	(g)					
52	Ratable Flow through of Credit						
53	Effective at 100% Basis Reduction						
54	Net Credit						
55							
56	Total Taxes Excl. Fed. & State Income Taxes						
57							
58	Revenue Requirement Applicable to Taxes						
59							
60	REVENUE FROM SALE OF BYPRODUCTS						
61	Revenue Requirement Applicable to Byproduct Sales						
62							
63	Revenue Requirement Prior to Edwardsport Credit						
64							
65	Less: Credit for Edwardsport Operating Expenses Included in Rates						
66							
67	Rev Requirement Applicable to Edwardsport Credit						
68							
69	Total Revenue Requirement Before Jurisdictional Allocation						
70	Retail Allocation Factor						
71	Total Retail Revenue Requirement						

EXHIBIT LA-12

Contains Information Designated as Confidential by DEI

EXHIBIT LA-13

Duke Energy Indiana, Inc.
Edwardsport IGCC
Adjustment for Edwardsport IGCC Plant Not Being In Commercial Operation During IGCC 12 and 13 Review Periods
(Dollars in Thousands)

Line No.	Description	IGCC-12	IGCC-13	Combined IGCC-12 and 13	Reference
		(A)	(B)	(C)	
	Retail Revenue Requirement Amounts:				
1	Retail Production Plant Depreciation Expense	$ 34,771	$ 54,872	$ 89,644	Notes A and B
2	Operating Expenses	$ 18,891	$ 32,573	$ 51,464	Notes C and D
3	Property Taxes	$ 12	$ 352	$ 363	Notes C and D
4	Retail Revenue Requirement for Costs That Would Not Be Expensed in IGCC 12/13 Period Based on Edwardsport IGCC Production Plant Not Being In Commercial Operation During IGCC 12/13 Review Period	$ 53,674	$ 87,797	$ 141,471	Note E
5	Adjustment to Retail Revenue Requirement for Edwardsport IGCC Production Plant Not Being In Commercial Operation During IGCC 12/13 Review Period			$ (141,471)	

Notes and Source

[A] IGCC-12, Petitioner's Exhibit C-2, page 7 of 11, line 12

Line No.	Description	Total	Equity AFUDC	All Other	Combined	Reference
		(D)	(E)	(F)	(G)	
6	IGCC-12, Petitioner's Exhibit C-2, page 5 of 11, line 6, Cols. B and C		9.02%	90.98%		
7	Retail Production Plant Depreciation Expense	$ 32,148	$ 2,900	$ 29,248	$ 32,148	
8	Revenue Conversion Factor		1.68953	1.02133		Note E
9	Retail Revenue Requirement Amounts		$ 4,899	$ 29,872	$ 34,771	

[B] IGCC-13, Petitioner's Exhibit B-2, page 7 of 12, line 14

Line No.	Description	Total	Equity AFUDC	All Other	Combined	Reference
10	IGCC-13, Petitioner's Exhibit B-2, page 6 of 12, line 6, Cols. B and C		9.02%	90.98%		
11	Retail Production Plant Depreciation Expense	$ 50,754	$ 4,578	$ 46,176	$ 50,754	
12	Revenue Conversion Factor		1.68495	1.02128		Note F
13	Retail Revenue Requirement Amounts		$ 7,714	$ 47,159	$ 54,872	

[C] IGCC-12, Petitioner's Exhibit C-2, page 7 of 11, lines 23, 24 and 26 as follows:

Line No.	Description	Operating Expenses	Property Taxes	Reference
		(H)	(I)	
14	Expenses	$ 20,151	$ 12.5	
15	Retail Allocation Percentage	0.9179	0.9179	
16	Retail Expenses	$ 18,497	$ 11	
17	Revenue Conversion Factor	1.02133	1.02133	Note E
18	Retail Revenue Requirement Amounts	$ 18,891	$ 12	

[D] IGCC-13, Petitioner's Exhibit B-2, page 7 of 12, lines 23, 24 and 26 as follows:

Line No.	Description	Operating Expenses	Property Taxes	Reference
19	Expenses	$ 34,747	$ 375.0	
20	Retail Allocation Percentage	0.9179	0.9179	
21	Retail Expenses	$ 31,894	$ 344	
22	Revenue Conversion Factor	1.02128	1.02128	Note F
23	Retail Revenue Requirement Amounts	$ 32,573	$ 352	

EXHIBIT LA-14

Duke Energy Indiana, Inc.
Edwardsport IGCC
Adjustment for Plant Performance During IGCC 12 and 13 Review Periods
(Dollars in Thousands)

Line No.	Description	IGCC-12 (A)	IGCC-13 (B)	Combined IGCC-12 and 13 (C)	Reference
	Retail Revenue Requirement Amounts:				
1	Jurisdictional revenue requirement return	$ 117,715	$ 115,610	$ 233,325	Notes A and B
2	Depreciation expense original project	$ 37,425	$ 37,396	$ 74,821	Notes C and D
3	Depreciation expense post-in-service additions		$ 15	$ 15	Notes C and D
4	Tax credits	$ (7,560)	$ (7,540)	$ (15,100)	Notes C and D
5	Net fixed costs for plant performance adjustment	$ 147,580	$ 145,481	$ 293,061	
6	Plant Operating Performance Not Achieved			55%	Note E
7	Adjustment to IGCC 12/13 Revenue Requirement for Poor Plant Performance			$ (161,184)	Line 5 x Line 6

Notes and Source

[A] IGCC-12, Petitioner's Exhibit C-2, page 4 of 11, line 11
[B] IGCC-13, Petitioner's Exhibit B-2, page 5 of 12, line 14
[C] IGCC-12, Petitioner's Exhibit C-2, page 5 of 11, lines 10 and 13
[D] IGCC-13, Petitioner's Exhibit B-2, page 6 of 12, lines 10, 13 and 16
[E] IGCC-12/13 combined, Joint Intervenors Exhibit B (Direct Testimony of David A. Schlissel), pages 23-24

EXHIBIT LA-15

Duke Energy Indiana, Inc.
Edwardsport IGCC
Adjustment for Excessive O&M Expenses During IGCC 12 and 13 Review Periods
(Dollars in Thousands)

Line No.	Description	IGCC-12 (A)	IGCC-13 (B)	Combined IGCC-12 and 13 (C)	Reference
1	Operating Expenses Per Petitioner	$ 18,497	$ 31,894	$ 50,391	Notes A and B
2	Limit Operating Expenses to IGCC-11 IG CX-5			$ 32,274	Note C
3	Adjustment to Remove Excessive Operating Expenses			$ (18,117)	Line 2 - Line 1
4	Revenue Conversion Factor			1.02128	
5	Adjustment to Revene Requirement to Remove Excessive Operating Expenses			$ (18,502)	Line 3 x Line 4

Notes and Source

[A] IGCC-12, Petitioner's Exhibit C-2, page 7 of 11, lines 23, 24 and 26 as follows:

		Operating Expenses (D)
6	Expenses	$ 20,151
7	Retail Allocation Percentage	0.9179
8	Retail Expenses	$ 18,497

[B] IGCC-13, Petitioner's Exhibit B-2, page 7 of 12, lines 23, 24 and 26 as follows:

9	Expenses	$ 34,747
10	Retail Allocation Percentage	0.9179
11	Retail Expenses	$ 31,894

[C] Operating Expenses per IGCC-11 IG-CX-5
Petitioner's Exhibit No. 28-E, pages 6 and 7 of 15, line 35, Estimated O&M Expenses Before Jurisdictional Allocation

	Month of Commercial Operation (E)	IGCC-11 IG-CX-5 Month (F)	Corresponding IGCC-12/13 Month (G)	IGCC-11 IG-CX-5 Amount (H)		Fraction of Initial Operating Month Adjustment (I)		Operating Expenses Adjusted for Initial Month of Operation (J)
12	1	Jan 2012	June 2013	$ 3,600	[D]	76.67%	[F]	$ 2,760
13	2	Feb 2012	July 2013	$ 3,600	[D]			$ 3,600
14	3	Mar 2012	Aug 2013	$ 3,600	[D]			$ 3,600
15	4	April 2012	Sept 2013	$ 3,600	[D]			$ 3,600
16	5	May 2012	Oct 2013	$ 3,600	[D]			$ 3,600
17	6	June 2012	Nov 2013	$ 3,600	[D]			$ 3,600
18	7	July 2012	Dec 2013	$ 3,600	[E]			$ 3,600
19	8	Aug 2012	Jan 2014	$ 3,600	[E]			$ 3,600
20	9	Sept 2012	Feb 2014	$ 3,600	[E]			$ 3,600
21	10	Oct 2012	Mar 2014	$ 3,600	[E]			$ 3,600
22	Total Before Jurisdictional Allocation			$ 36,001				$ 35,161
23	Retail Allocation Percentage							0.9179
24	Retail Expenses							$ 32,274

		Total (K)	Monthly (L)
[D]	Jan - June 2012	$ 21,601	$ 3,600
[E]	July - Dec 2012	$ 21,600	$ 3,600
	First 12 months	$ 43,201	

[F]	June 8-30, 2013	23	operating days
		30	total days in month
		76.67%	fraction of month claimed by Petitioners for Commercial Operation

EXHIBIT LA-16

CAC
IURC Cause No. 43114 IGCC-12
Data Request Set No. 2
Received: March 20, 2014

CAC 2.1

Request:

In his prefiled testimony in Cause No. 38707-FAC-99, DEI witness Swez states, in pertinent part:

> On June 7, 2013, the Edwardsport IGCC generating station began commercial operation and has since performed as expected. For example, on August 9, Edwardsport IGCC reached approximately 586 net MW output under syngas production. Since commercial operation, the station has produced electricity using both syngas and natural gas, with the majority of production from syngas. . . .
>
> During times when Edwardsport IGCC is performing testing, tuning, and optimization, the station is offered [to MISO] with a commitment status of must-run
> with the minimum and maximum output dictated by the specific schedule and unit availability. During these situations, the output of the station is coded as testing. The Company's offer to MISO essentially results with the MISO dispatch following the output of the units during this time rather than MISO determining the level of output the unit. However, during situations when syngas is not available,
> testing, tuning, and optimization is not required with natural gas operation, and the
> station is available on natural gas operation, the unit is offered to MISO as an economic resource and can be committed and dispatched at MISO's discretion. During these situations, the output of the station is not coded as testing.

With respect to the time period of June 7, 2013 through February 28, 2014, please provide the following information relative to the operation of the Edwardsport IGCC generating station:

a. By individual calendar date, the number of hours during which the output of the station has been coded as testing and the amounts of generation and resulting revenues during those hours;

b. By individual calendar date, the number hours during which the output of the stations has NOT been coded as testing but instead offered to MISO as an economic resource and the amount of generation and resulting revenues during those hours;

c. By individual calendar month, the number of hours during which the output of the station has been coded as testing and the amounts of generation and resulting revenues during those hours;

d. By individual calendar month, the number of hours during which the output of the station has NOT been coded as testing but instead offered to MISO as an economic resource and the amounts of generation and resulting revenues during those hours;

e. By individual calendar date, the minimum and maximum output during the period the station was classified as testing;

f. By individual calendar date, the minimum and maximum output during the period the station was NOT classified as testing but instead offered to MISO as an economic resource;

g. By individual calendar date, the amounts of generation produced from syngas and natural gas, respectively; and

h. By individual calendar month, the amounts of generation produced from syngas and natural gas, respectively.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is not reasonably calculated to lead to admissible evidence in this proceeding. The relevant time period for this proceeding is April 1, 2013 through September 30, 2013. Duke Energy Indiana objects to producing information from outside of the relevant time period. Duke Energy Indiana also objects to this Request to the extent it has a different definition of the term "testing" than Mr. Swez used in his FAC testimony. Duke Energy Indiana's response to this Request is per Mr. Swez's understanding and use of the term "testing." Duke Energy Indiana further objects to subparts (g) and (h) of this Request on the grounds that the Plant's metering does not differentiate between electrical energy produced by gasified coal or natural gas.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. All hours Edwardsport ran during the time period in question have been categorized as "testing," with assignment to native load, for purposes of stacking generation in the Company's PACE model. This is consistent with the Company's categorization of generation during testing periods at other generating units. Note that during the time period in question, Edwardsport was not cleared by MISO while being offered with a commitment status of "Economic" in any hour and thus, all generation was the result of a "Must Run" commitment status. In addition, see Attachment CAC 2.1 A, which represents the real-time generation, as well as the day-ahead asset energy, real-time non-excessive, and real-time excessive energy amounts from Edwardsport. Note that this represents only the revenues as a result of the units' participation in only the MISO energy markets. To calculate all "resulting revenues," additional credits and adjustments from ARRs/FTRs, capacity, ancillary services, distribution of losses, make whole payments, etc. would need to be included.

b. Please see the Company's response to subpart (a) above.
c. Please see the Company's response to subpart (a) above.
d. Please see the Company's response to subpart (a) above.
e. Please see the Company's response to subpart (a) above.
f. N/A
g. See above objection.
h. See above objection. Answering further, please see Confidential Attachment OUCC 3.2-A, as previously produced in this proceeding.

EXHIBIT LA-17

[redacted]

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

CONFIDENTIAL RESPONSE
DEI-IG 4.24

Questions relating to Stultz's testimony in 13:

Request:

Refer to Mr. Stultz testimony in IGCC 13, pages 12-14. Please provide:

a. The capacity factor attained by the Plant for each month covered by IGCC 12 and 13 (April 2013-March 2014) when running on syngas.
b. Explain how the monthly numbers provided in "a" were calculated.

Objection:

Duke Energy Indiana objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding. Capacity factor is not the best measure of a generating unit's performance because it is penalized when not dispatched by MISO for economic reasons (such as during periods of transmission constraints or high natural gas prices for a plant able to run on natural gas), although is still available. Further, Duke Energy Indiana objects to this Request to the extent it seems to discount the fact that Edwardsport can and does produce MWhs on both natural gas and syngas.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. [redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

b. [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: September 22, 2014

CONFIDENTIAL RESPONSE
DEI-IG 6.1

Request:

Please reference *Edwardsport IGCC Project Progress Report Number: 67*, bates 090015313-0000938 ("Progress Report 67").

a. Is Progress Report 67 the last monthly progress report that has been prepared? If, so, why?

b. Since December 2013, have progress reports been prepared in any other format? If so, please provide all such progress reports.

c. Please reference page 15 of Progress Report 67, bates 090015313-0000952. Have any updated versions of this graph been prepared since December 2013? If so, please provide all such graphs.

d. Please provide all charts/graphs prepared after December 2013 that depict any of the following information:

i. Projected substantial completion date/s
ii. Actual substantial completion date/s
iii. Projected final completion date/s
iv. Actual final completion date/s
v. Gasifier operations
vi. Gasifier trips
vii. Planned outages
viii. Unplanned outages
ix. In service date

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is overbroad and unduly burdensome, particularly as the Request seeks "all charts/graphs…." Duke Energy Indiana also objects to this Request as not reasonably calculated to lead to admissible evidence to the extent it seeks information prepared after March 31, 2014. Duke Energy Indiana also objects to this Request as vague and ambiguous.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Yes. The monthly progress reports were prepared by the Edwardsport project construction management group and they determined it was no longer necessary to prepare given that construction has largely been completed.

b. No.

c. No.

d. Please see Confidential Attachment DEI-IG 6.1-A. For an update of the gasifier operations data maintained in the normal course of business, please see the confidential information below:

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

EXHIBIT LA-18

BEFORE THE MISSISSIPPI PUBLIC SERVICE COMMISSION

MISSISSIPPI POWER COMPANY **DOCKET NO. 2009-UA-014**
EC-120-0097-00

IN RE: PETITION OF MISSISSIPPI POWER COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE ACQUISITION, CONSTRUCTION, AND OPERATION OF AN ELECTRIC GENERATING PLANT, ASSOCIATED TRANSMISSION FACILITIES, ASSOCIATED GAS PIPELINE FACILITIES, ASSOCIATED RIGHTS-OF-WAY, AND RELATED FACILITIES IN KEMPER, LAUDERDALE, CLARKE, AND JASPER COUNTIES, MISSISSIPPI

FINAL ORDER ON REMAND GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY, AUTHORIZING APPLICATION OF BASELOAD ACT, AND APPROVING PRUDENT PRE-CONSTRUCTION COSTS

COMES NOW, the Mississippi Public Service Commission ("Commission") and, for the reasons stated herein, hereby grants Mississippi Power Company's ("MPCo" or "the Company") Petition filed in this cause and issues a certificate of public convenience and necessity authorizing the acquisition, construction and operation of the Kemper County IGCC Project ("the Kemper Project" or "Kemper" or "the Project"). This Final Order on Remand is being issued by the Commission pursuant to the decision and mandate of the Mississippi Supreme Court issued in Cause No. 2011-CA-00350-SCT. The Supreme Court's opinion reversed our certificate orders, holding that the orders lacked the requisite findings and failed to cite sufficient evidence from the record to support the conclusions reached in approving the Kemper Project, as defined herein.[1] The Court did not render an opinion on whether the record in this proceeding

[1] The Supreme Court's opinion requires that the Commission "make findings supporting its decision" and further requires that those "findings must be 'supported by substantial evidence presented' which 'shall be in sufficient detail to enable [this] court on appeal to determine the controverted questions presented, and the basis of the commission's conclusion.'" Opinion of Mississippi Supreme Court, Case No. 2011-CA-00350-SCT, ¶ 2 (Mar. 15, 2012) (citing MISS. CODE ANN. § 77-3-59 (Rev. 2009)). By reversing the Commission's June 2010 Order the April and May 2010 Orders, which were incorporated by reference in and provided the findings and rationale upon

actually contains substantial evidence on which to base our decision to approve the Kemper Project. We find that the record as comprised as of June 3, 2010, is complete, negating the need for the Commission to hold additional hearings, request additional evidence, or further supplement the record. Fundamental to this finding is the professional and ongoing monitoring of the Kemper Project conducted by the Commission's and the Public Utilities Staff's ("Staff") respective Independent Monitors ("IMs"). The continuing activities of the IMs and the periodic economic viability evaluations of the Kemper Project eliminate any need to receive evidence from any third-party concerning the current status of the Kemper Project or the general state of the economy and fuel markets.

The decision of the Commission to render a decision on the record as currently comprised without holding additional proceedings on remand is fully within the discretion of the Commission under Mississippi law.[2] In light of the Supreme Court's order and the issues raised on appeal, the Commission finds that its original approach resulted in confusion as to the Commission's actual determination and the findings of law and fact relied upon in reaching its determination and seeks to remedy any insufficiencies by issuance of this new Final Order on Remand. Through its original orders the Commission intended to approve the Kemper Project so that Mississippi customers could enjoy the benefits of Kemper's baseload energy and stable,

---

which the June 2010 Order was based, were likewise reversed and thereby voided and annulled. Consequently, the Commission must issue a new Order in accordance with the Supreme Court's decision and mandate.

[2] *McGowan v. Miss. Oil & Gas Bd.*, 604 So. 2d 312, 324 (Miss. 1992) ("The Board may, if it deems it appropriate, stand by its prior orders, provided only that it make more than conclusory 'written findings of fact and conclusions of law setting forth the reasons for the Board's decision.' Nothing said here implies so much as a hint what the Board should do, so long as its further proceedings are not inconsistent with this opinion."); *see also Estate of Bolden v. Williams*, 17 So. 3d 1069, 1073 n.5 (Miss. 2009) ("Upon remand of a case for a new trial - absent a directive from this Court to the contrary - the decision of whether to reopen discovery and other pretrial matters in a case is left squarely within the sound discretion of the trial court, and the trial court's decision, absent an abuse of that discretion, will not be disturbed.") (citing *Banks v. Hill*, 978 So. 2d 663, 665 (Miss. 2008)); *see also Florida Power & Light Co. v. Lorion*, 470 U.S. 729, 744 (U.S. 1985).

low-cost fuel, while at the same time providing the customer protection from what we viewed as unique risks associated with the Kemper Project.

The Commission's approval of Kemper in the April 29, 2010, Order ("April Order") essentially required that the Company assume all of the risks and uncertainties of the Project. In response, MPCo filed what was in essence a Motion for Reconsideration. Attached to the motion were exhibits showing developments with Kemper since Phase Two Hearings held in February. Those exhibits showed that some of the risks of Kemper had been either mitigated or eliminated. In addition, MPCo advised it could not finance or build Kemper under the conditions contained in the April Order. MPCo then set forth alternative conditions that would allow it, albeit under less than the terms it originally proposed, to build Kemper. We allowed all parties to comment on that Motion and held several open meetings before issuing the May 26, 2010, Order ("May Order").

As is proper on remand,[3] the Commission has carefully re-examined, reviewed, and considered the documents, evidence, testimony, and record in both Phase One and Phase Two of these proceedings in full. We have given particular consideration to the issues that were raised on appeal by the parties, and to ensuring that each finding on remand is set forth in sufficient detail, with appropriate record references where applicable, such that all of our findings are supported by substantial evidence as presented in this Order and contained in the record. By way of illustration and not by limitation, we have carefully considered (i) the substantial record evidence which overwhelmingly supports the issuance of the certificate of public convenience and necessity allowing construction of the Kemper Project; (ii) the evidence presented regarding

[3] *See McGowan*, 604 So. 2d at 324 (recognizing the agencies freedom to do anything not inconsistent with the opinion of the reviewing court); *see also* 2 AM. JUR. 2D *Administrative Law* § 576 (2004) ("[U]nless the remand to an agency limits the issues to be considered, the case should be viewed in its entirety.") (citing *City of Hampton v. Iowa Civil Rights Comm'n*, 554 N.W.2d 532 (Iowa 1996)).

the risks, real or perceived, associated with the construction of any baseload facility, as well as those associated with the implementation of a new technology; (iii) the evidence regarding various fuel and environmental compliance scenarios presented; and (iv) the evidence regarding the overall allocation of risks and benefits of the Kemper Project to MPCo, its shareholders, and its customers. Based upon this full re-examination and re-consideration of the record and in accordance with the Supreme Court's decision and pursuant to the Mississippi Public Utility Act[4] ("the Act") and the Commission's Public Utilities Rules of Practice and Procedure ("the Rules"), the Commission finds as follows:

I. SUMMARY OF COMMISSION FINDINGS

1. This docket represents the most thoroughly analyzed certificate petition ever presented to the Commission. Several parties actively participated throughout and many issues were debated. The Commission took a measured approach to the review of the Company's requests and finds that a full opportunity for discovery and the submission of evidence was afforded all parties. As such, the record in this proceeding contains substantial evidence to support the findings contained in this Order.

2. The Commission finds it unnecessary to re-open the record to consider new evidence, particularly proposed lower natural gas forecasts, as urged by the Mississippi Chapter of the Sierra Club ("Sierra Club") and Entegra Power Group, LLC ("Entegra"). Pursuant to the original orders setting forth the conditions and approval of the Kemper Project, the Commission and the Staff engaged IMs to scrutinize the Project. Among other things, the Commission's IM maintains a continuous presence on the job site, conducts various site and record inspections, tracks the Project's accounting, routinely holds meetings with the Company, maintains close

[4] MISS. CODE ANN. §77-3-1, *et. seq.*

contact with Commission staff and provides monthly reports to the Commission. Additionally, MPCo provides monthly progress reports and periodic viability reviews that track the economics of the Kemper Project in light of a range of natural gas forecasts, among other considerations. These reports are reviewed by the IMs. This Commission is aware and apprised of natural gas forecasts. Recently, in Docket No. 2010-UA-279, the Commission considered whether to grant MPCo a facilities certificate to install environmental control measures on the Company's coal units at Plant Daniel. The Commission considered recent natural gas price forecasts and the economic comparison between a self-built natural gas-fired combined cycle option and the proposed controlled coal units. The Commission found that, given the range of natural gas price forecasts, maintaining the coal units best served the public interest by providing fuel diversity and greater price stability. The Commission finds that, through its IM, the periodic viability reviews and other Commission proceedings, it is fully aware of natural gas forecasts and declines the invitation of Sierra Club and Entegra to reopen the record in this case. Should the need occur, the Commission possesses the authority to reconsider any certificate issued.

3. In Phase One, the Commission determined that MPCo had a need for additional generating capacity. These findings were based upon a thorough Integrated Resource Planning ("IRP") process presented by the Company and analyzed by all of the parties, including the Staff. No evidence was presented in Phase Two that would cause the Commission to reconsider, and we hereby confirm and incorporate the findings contained in the Commission's Phase One Order.[5] Finding that a need existed, it was then necessary to determine the best resource or resources available to meet this need.

[5]The Phase One Order was not contested on appeal.

4. For all of the reasons provided in this order, the Commission finds that the public convenience and necessity requires and will require the acquisition, construction, and operation of the Kemper Project as approved in this Order. We find, based upon our re-examination of the record in this proceeding that the Kemper Project is the best overall alternative to meet the identified need and to provide reliable energy and capacity at low, stable fuel prices for the next several decades. The Commission's consideration of the Kemper Project involved the evaluation of the relative economics of other available alternatives, an analysis of the risk posed by each option to both MPCo and its customers, and the strategic benefits offered by each alternative. By this Order, we make explicit what was implicit in our previous orders: the Kemper County IGCC Project, given its low, stable fuel prices, its overall economics, and its significant contribution to preserving a reasonable level of fuel diversity for MPCo's generation portfolio satisfies the Commission's preference for a long-term baseload resource that will provide reliable service to MPCo's customers for the next 40 years.

5. To evaluate the economics of each alternative, the Commission used the same scenario approach adopted in Phase One, which evaluates alternatives across a range of reasonable fuel and carbon compliance forecasts. The Commission finds that the use of a range of scenarios to evaluate the relative economics of all available alternatives was a prudent and effective approach. An issue in the case was the relative credibility of various natural gas price forecasts. For the reasons provided herein, the Commission declines to pick a specific forecast or set of forecasts. Instead, the Commission elects to consider the effect of the range of natural gas prices on the economics of the alternatives under all credible scenarios.[6]

[6] The Independent Evaluator agreed with this approach noting that the "use of scenarios is a good way to measure risks. We would tend to pick the option that wins a majority or more of the scenarios because it means that the option is the best deal for Mississippi ratepayers no matter how the future unfolds." Report of the Independent

6. In his testimony, Dr. Roach, the Independent Evaluator, indicated that as part of the Commission's decision, the Commission must make a strategic choice as to whether it preferred long-term or short term resource solutions.[7] MPCo and the Commission have obligations under the Act to ensure that customers are being served safely, reliably, and in a cost-effective manner. Notably, the Legislature has stated its policy preference for the development of diverse baseload capacity and energy.[8] The regulated utility industry is characterized by large, long-lived capital investments, which does not easily allow for a utility to ignore long-term planning needs or the consequences of making a short-term decision. Based on its review of the evidence in the record and the considerations discussed above, the Commission finds that a long-term resource solution is in the best interest of MPCo's customers and is the strategic choice of the Commission.

7. After re-examining the record and testimony, the Commission finds that the intervening IPPs' "fixed gas" bids were not supported by credible evidence and do not warrant further consideration as viable alternatives to meet MPCo's resource needs, particularly in light of our strategic preference for a long-term resource solution. No party to these proceedings was willing to fix the price of natural gas themselves, making their claims that a "fixed gas" price deal could be done mere speculation. Once the fixed gas proposals are removed from consideration, the overwhelming weight of economic evidence in the record supports a finding that the Kemper Project is the most economic resource available.

8. Aside from its economic advantage, the Kemper Project also provides significant strategic benefits to MPCo, its customers, and the State. All of these benefits are laid out in

Evaluator, p. 3 (Jan. 25, 2010).

[7] Phase Two Hearing Transcript, pp. 1122-23.

[8] MISS. CODE ANN. § 77-3-101.

detail in this order, but paramount among them is the fuel diversity the Project provides. Today, MPCo's generating fleet is limited to two fuels, traditional coal and natural gas. If Plant Watson Units 4 and 5 remained uncontrolled, over 70% of MPCo's existing fleet will be burning natural gas. Such dependence on one fuel source is not prudent for an electric utility or its customers. The record has extensive evidence on natural gas prices since they were deregulated in the 1970's, and two things are not rebuttable. During that time natural gas prices have been extremely volatile, and their trend in pricing has been upward for the last 50 years. Kemper will provide MPCo and its customers a long-term, low stable-priced fuel in locally mined lignite. The fuel diversity and price stability offered by Kemper to the customers of MPCo is a significant factor supporting the Commission's decision. The Commission finds that maintaining long-term fuel diversity is critical to keeping MPCo's prices to customers low and stable over the next several decades.

9. We recognize that there are increased costs and risks inherent in any new baseload facility due primarily to the long construction time for such facilities and the typically higher capital cost associated with such facilities, particularly coal or nuclear resources. Based on a full examination of the record, we perceive the magnitude of cost and risk with respect to Kemper to be equal or greater than other baseload facilities, given the cost of the proposed facility, the size of MPCo relative to the Project, the new technology being employed in the Plant, and the alternative cost recovery mechanisms requested under the Baseload Act.[9] In essence, the Kemper Project presents a unique challenge for the Commission in terms of balancing our obligations as established by the Legislature (i) to evaluate new facilities under the

[9] MISS. CODE ANN. § 77-3-101, *et. seq.*

well-established certificate process established in the Act, and (ii) to promote new baseload generation facilities, such as Kemper, under the Baseload Act.

10. To that end, each condition contained in this Order is designed to appropriately balance the risk between MPCo and its customers and one or more of the uncertainties identified. First, the purpose of the cost cap (which is more fully described below) is to insulate customers from large construction cost overruns by shifting this risk to the utility at a certain total cost level beyond which customers are no longer responsible, even if the costs are found to be prudent. Second, the operational cost and performance parameters apply similarly to the operational cost estimates assumed in the Company's analysis during the hearings. The operational cost and performance parameters assure that ratepayers will not pay for an underperforming asset. Third, the Commission made clear that nothing in this order will diminish the provisions in the Baseload Act related to plant cancellation—a risk that was discussed by several parties. Fourth, with respect to incentives, the Company must demonstrate that it used its "best efforts" to procure the incentives identified by the Company before recovering any additional costs from customers resulting from the loss of any incentive. Fifth, the Commission re-iterates that the Company should use all diligence to obtain and maintain all of the permits necessary to construct and operate the Project and keep the Commission informed of any issues related thereto. Finally, the Commission requires that the Company periodically re-evaluate the economic viability of the Kemper Project to confirm that it remains in the overall best interest of customers. This last condition helps mitigate the risk that a better option becomes available because of subsequent changes in the technology, cost, energy markets and/or utility regulation.

11. The Commission finds that the Kemper Project is a "generating facility" as defined in the Baseload Act. The Commission also finds that there are two primary benefits to

awarding rate recovery of financing costs on "Construction Work in Progress" (CWIP): (1) it will save customers money over the life of the Project; and (2) it will help MPCo maintain the financial strength needed to complete the Kemper Project. Therefore, the Commission finds that it is in the public interest for the Commission to exercise its CWIP authority under the Baseload Act in the manner described in more detail later in this Order.

12. The Commission finds that the "used or useful" doctrine is distinct from the Baseload Act and rejects and declines any application of the Baseload Act that would undermine the independent safeguards of the used and useful doctrine.

13. In summary, we find that the present and future public convenience and necessity requires and will require the construction, acquisition, operation, and maintenance of the Kemper Project as approved herein.

II. BACKGROUND AND PROCEDURAL HISTORY

A. PROCEDURAL HISTORY.

14. On January 16, 2009, MPCo filed its Certificate Filing, including its petition, testimony and supporting documents, as amended and supplemented from time to time,[10] seeking a certificate of public convenience and necessity authorizing the Company to construct, acquire, operate, and maintain a new electric generating facility in Kemper County, Mississippi. Specifically, MPCo's Certificate Filing requested that the Commission (i) issue a certificate of public convenience and necessity authorizing the acquisition, construction, extension, operation and maintenance of the Kemper Project, as defined below; (ii) apply the Commission's authority

[10] The Company amended and supplemented its Certificate Filing through the following submissions in this Docket: (i) Supplemental Filing for Phase One--Need, filed July 8, 2009; (ii) Rebuttal Filing for Phase One--Need filed July 28, 2009; (iii) Second Supplemental Filing for Phase One--Need, filed August 28, 2009; (iv) Third Supplemental Filing, filed December 7, 2009; (v) Phase Two Rebuttal Filing, filed January 5, 2010; and (vi) Phase Two Supplemental Filing, filed January 25, 2010.

under the Baseload Act, Miss. Code Ann. § 77-3-101, *et seq.* and (iii) approve the Company's pre-construction costs incurred in connection with the screening and evaluation of generating alternatives and the various pre-construction activities undertaken by the Company in connection with the Project.

15. Notice was given as required by law to all parties interested therein by mailing such notice to each public utility which may be affected, by publication on January 26, 2009, in The Clarion Ledger, a newspaper of general circulation in Jackson, Mississippi, and by publication in the following newspapers of general circulation where the facilities are to be located on the following dates:

The Meridian Star, on January 28, 2009, in Lauderdale County;

The Jasper County News, on January 28, 2009, in Jasper County;

The Kemper County Messenger, on January 29, 2009, in Kemper County; and

The Clarke County Tribune, on January 30, 2009, in Clark County.

16. The Mississippi Public Utilities Staff ("Staff") actively participated in this proceeding through its Litigation Section, led by the Staff's General Counsel, George M. Fleming, Esq., and other Staff members assigned to participate in the Litigation Section. Those members of the Staff not assigned to the Litigation Section were designated to assist the Executive Director of the Staff, Robert G. Waites, Esq., as advisors to the Commission and appropriate safeguards were put in place to segregate the functions of the Litigation Section from the functions of the Advisory Section.

17. In addition, the following parties petitioned the Commission for and were granted leave to intervene in this proceeding all in accordance with RP 6 of the Rules:

South Mississippi Electric Power Association ("SMEPA")

Entergy Mississippi, Inc. ("EMI");

Mississippi Chapter of the Sierra Club ("Sierra Club");

Entegra Power Group, LLC ("Entegra");[11]

Ergon, Inc. ("Ergon");

Jim Hood, Attorney General of the State of Mississippi ("AGO");

Magnolia Energy, L.P. ("Magnolia");[9]

Queshaun Sudbury, individually;

Steve McKenna, individually;

International Energy Solutions, Inc. ("IES");

KGen Power Management, Inc. ("KGen");[9] and

Calpine Corporation ("Calpine").[9]

B. INVESTIGATION OF MPCO CERTIFICATE FILING

18. By order dated June 5, 2009, the Commission initiated an evaluation and investigation of MPCo's Certificate Filing and established a two phase procedural schedule pursuant to which the Commission administered the issues presented in this Docket. Phase One was designed to evaluate MPCo's IRP and determine whether there was a need for additional capacity and energy. Phase Two was designed to address what resources are available to meet the need determined in Phase One, and to identify the likely costs of those resources.

19. The Commission and the Staff separately retained expert consultants to assist them independently in evaluating MPCo's Certificate Filing and to participate in the investigation and hearings in Phase One, all of which is described in the Phase One Order. For

[11] Entegra, Magnolia, KGen and Calpine are all Independent Power Producers (IPPs) that will sometimes be referred to collectively as the IPPs.

Phase Two, which included an evaluation of resource alternatives and the Company's pre-construction costs, the Commission and Staff again utilized expert consultants to assist them in their evaluation of the Project and other resource alternatives. As it did in Phase One, the National Regulatory Research Institute (NRRI) continued its participation in an advisory role to the Commission through its principal Scott Hempling, Esq. In addition, Boston Pacific, Inc. consulting firm and its principal Dr. Craig Roach continued its participation as an independent consultant in these proceedings. For Phase Two, the Commission expanded Dr. Roach's role to include evaluating MPCo's proposed Project as well as the various other resource proposals submitted in Phase Two and to present written and oral testimony at the Phase Two hearing. The Staff retained Larkin and Associates, PLLC ("Larkin"), and its accountant, Ralph C. Smith, to audit and review the prudence of pre-construction costs incurred by MPCo through March 31, 2009.

20. The Commission takes notice that several parties, including the Commission's and Staff's consulting and testifying experts and the Litigation Section of the Staff, conducted extensive discovery over the course of these proceedings on the many issues that related to MPCo's Certificate Filing in both Phase One and Phase Two. Over 1,000 separate data requests/responses (many containing multiple sub-parts) were exchanged between and among the parties, all of which were submitted into the record of this proceeding. A number of intervenors including the AGO, the Sierra Club and various IPPs also provided testimony, briefs and other documents to the Commission concerning many of the issues raised by the Commission in this proceeding. The Commission and Staff and their respective consultants engaged in a thorough evaluation and investigation of the Company's Certificate Filing as well as the testimony, evidence and resource alternatives offered by other parties in this proceeding. These experts,

along with MPCo and the other intervenors, provided testimony during the hearings. Finally, many letters, emails, phone calls and hearing comments were received from the public both in support of and in opposition to MPCo's proposed Kemper County IGCC Plant. The Commission findings presented herein are each based upon a careful review of all of the evidence in the record as well as the Commission's knowledge and expertise in the regulation of electric public utilities.

21. As stated above, over 1,000 data requests were exchanged between and among the parties, including substantial amounts of confidential and proprietary information, including trade secrets, exchanged pursuant to confidentiality agreements executed by and among many of the parties. This exchange of confidential information clearly benefitted the parties and the Commission in the administration of this Docket. By Commission Order, all responses to data requests were also filed with the Executive Secretary and were incorporated into the official file and record of this proceeding. All confidential information has been filed under seal and will be included in the record under seal to protect the confidential information of the respective parties contained therein. The Commission finds that a full opportunity for discovery was afforded all parties and that the record in this proceeding contains substantial evidence supporting the Commission's findings.

C. Summary of Phase One and Phase Two Proceedings

22. Hearings on Phase One issues were held on October 5-9, 2009. Following the Phase One hearings, the Commission issued its Order Finding Need for Generating Capacity and Energy on November 9, 2009 (Phase One Order), wherein it found, *inter alia*, that (i) MPCo's load forecast and load forecasting methodology are reasonable; (ii) MPCo demonstrated a need under all sixteen scenarios for additional capacity and energy ranging from approximately 304

MW to 1,276 MW in the 2014-2015 time frame; (iii) the Company's retirement assumptions for Plant Watson Units 1-3 in 2013 and Plant Eaton Units 1-3 in 2012 are reasonable; (iv) some level of CO_2 emission regulation is expected to be enacted; and (v) demand-side management programs (DSMs) and renewables, although included in MPCo's planning scenarios, are inadequate to meet the identified need. Finally, the Commission found that based upon all of the evidence in the Phase One record, the public interest required the Commission to proceed to Phase Two and to assess the available resources to meet MPCo's identified need. No evidence was presented in Phase Two that would justify any changes in the findings of fact or conclusions of law rendered by the Commission in its Phase One Order, and the Commission hereby adopts in its entirety its Phase One Order as if fully restated herein.[12]

23. For Phase Two, the Commission summarized its expectations in our June 5, 2009, order as follows:

> Phase Two will address what resources are available to meet the need determined in Phase One, and what are the likely costs of those resources. Resources include, but are not limited to, utility-built resources, purchased power (including power purchased through competitive bidding), and demand-side resources. Parties may propose alternatives to meet the need established in Phase One. Any party wishing the Commission to take seriously its position on resource options for the territory served by MPCo should submit testimony on the technology, timing and cost of those options. Simply stating "no" or "not now" to another party's proposed resource does not assist the Commission in meeting its responsibilities.

24. Also in its June 5, 2009, order, the Commission propounded certain data requests to all parties of record related to the resource options available to fill MPCo's capacity and energy needs established in Phase One. By separate orders dated November 9, 2009, and December 1, 2009, the Commission further defined the procedures that would govern the

[12] Notably, the Commission's Phase One Order was not challenged on appeal.

administration of Phase Two of this proceeding. By those orders, the Commission established a procedural schedule for Phase Two, which allowed additional parties an opportunity to intervene for the purpose of submitting competing resource proposals to compare and evaluate against the Company's resource proposal. We also established a list of minimum bid requirements that were applicable to all potential bidders in Phase Two and directed MPCo to address various issues for which the Commission sought additional information in Phase Two. In addition, the procedural schedule created by the various orders described herein established, *inter alia*: (i) deadlines for filing direct and rebuttal testimony on Phase Two issues; (ii) deadlines for filing resource evaluation reports and analyses; (iii) a pre-hearing conference; (iv) hearing dates for Phase Two; (v) a panel procedure for use during the hearings; (vi) a briefing schedule for post-hearing issues; (vii) and a decision date by the Commission. The procedural schedule provided adequate time for all parties of record to conduct discovery and to conduct such investigation and examination of the various resource options proposed by the parties.

25. By order dated January 4, 2010, the Commission supplemented its previous orders in this Docket by establishing the procedures for the Phase Two hearings and by providing for those hearings to be organized and conducted in six distinct issue panels similar to the manner the Phase One hearings were conducted. Prior to the Phase Two hearings, a pre-hearing conference was also conducted in which procedural matters and hearing format were discussed in greater detail and agreed upon by the parties and the hearing examiner, Robert G. Waites, Esq., Executive Director of the Staff.

26. Hearings were held in the hearing room of the Commission beginning on February 1, 2010, and continuing until February 4, 2010, all consistent with the procedures previously established by the Commission. Limited portions of the hearings discussing

confidential, proprietary and trade secret information were closed to the public and to those parties that had not executed appropriate confidentiality agreements affording them access to confidential information of MPCo and/or the other parties. Public witnesses were allowed to address the Commission regarding MPCo's application on February 5, 2010, and those public comments are in the record in this proceeding. In addition, the Commission allowed written comments to be received until March 12, 2010, after which the public comment period was closed.

27. At the beginning of the Phase Two hearings, the Commission again reiterated its intent to fully develop the record on all Phase Two issues. The Commission overruled the Company's renewed and continuing objection from Phase One objecting to the issue panel format as constituted, and the testimony and record at hearing were developed in accordance with the issue panels established by the Commission in its January 4, 2010, order. The purpose of the panel procedure was to develop testimony on the key issues that affect a resource evaluation and selection decision. While the panel procedure was an unusual and unique method of handling a case such as this, the Commission finds that the parties did have a fair opportunity to present their respective cases and to fully develop the issues related to the various resource proposals submitted for consideration and evaluation.

D. PREVIOUS COMMISSION ORDERS

28. At the conclusion of the Phase Two Hearings, the Commission issued its Order for Post Hearing Information requesting that the parties propose customer protection measures to mitigate some of the risk borne by customers from Kemper and the IPP proposals.[13] Several parties submitted proposals on March 12, 2010, including MPCo. MPCo's revised Kemper

---

[13] MPSC Order for Post-Hearing Information (Feb. 11, 2010).

proposal included a voluntary construction cost cap of 30% over its estimate (representing up to an $800 million increase over its estimate), operational cost and performance measures, and equipment guarantees for certain portions of the first-of-a-kind gasification technology.[14] It should be noted that MPCo's March proposal represented a significant compromise to the Company's original position taken in its Pre-Hearing Brief, that cost caps were neither appropriate nor authorized by law.[15]

29. On April 29, 2010, the Commission issued its April Order as required by the Act and the Commission's Scheduling Order imposing conditions on the approval of the Kemper Project.

30. In response, MPCo filed its Motion in Response to Commission Order, or, in the Alternative, Motion for Alteration or Rehearing ("Motion" or "Motion for Reconsideration").[16] By subsequent order of the Commission, the provisions of the April Order were stayed until the Commission could consider and rule upon the Company's Motion.[17] Other parties were also permitted to be heard on the Company's Motion by filing written responses to the Company's Motion.[18]

31. In its Motion, the Company provided several material updates to the Kemper Project that occurred since the Phase Two hearings held in February. These updates served to

---

[14] MPCo's Post Hearing Submission and Answer to Questions (Mar. 12, 2010).

[15] MPCo's Phase Two Pre-Hearing Brief (Jan. 25, 2010).

[16] MPCo's Motion in Response to Commission Order or in the Alternative Motion for Alteration or Rehearing (May 10, 2010) [hereinafter "Motion for Reconsideration"].

[17] MPSC Order, suspending part XIII of order (May 17, 2010).

[18] Entegra/Calpine Response to MPCo Motion (May 13, 2010); Queshaun Sudbury's Opposition to MPSC Proposed Final Order (May 25, 2010).

address several of the items listed in Article VII of the April Order. Among the information provided in its Motion, the Company described and updated the status of the following:

Listing of current confirmed construction costs amounting to 20% (instead of 10% available at Phase Two hearings) of total construction costs based upon executed contracts, memoranda of understanding, letters of intent, or vendor bids;[19]

Update on current status of ash handling requirements, which indicate that such proposed regulations would not apply to the Project;[20]

Update on acquisition of rights-of-way for transmission lines (34% obtained), the gray water pipeline (21% obtained), the natural gas pipeline (48% obtained);[21]

Update on acquisition of lignite leases and representing the generally accepted practices for such acquisition;[22]

Update on status of CO_2 off take agreement negotiations;[23]

Issuance of modified PSD Construction Permit from Mississippi Environmental Permit Board on March 9, 2010 (authorizing the commencement of construction);[24]

Update on NEPA Environmental Impact Statement;[25]

Confirmation of $279 million allocation of Section 48A Phase II investment tax credits (Company filing assumed only $200 million);[26]

---

[19] *See* MPCo's Motion for Reconsideration, p. 26 (May 10, 2010).

[20] *Id.* at 15-16.

[21] *Id.* at 16-18.

[22] *Id.* at 18.

[23] *Id.* at 19.

[24] *Id.* at 20.

[25] *Id.* at 21-22.

[26] *Id.* at 22-23.

Execution of Sponsor Payment Letters to commence "Project Evaluation" phase of U.S. Department of Energy (DOE) Loan Guarantee Program;[27]

Agreement in principle reached with North American Coal for a forty-year Lignite Mining Agreement;[28] and

Expectation that DOE will advance the recognition of $245 million during the construction phase of the Project under the CCPI2 cooperative agreement.[29]

32. The Company's Motion also requested that the Commission modify the proposed conditions based upon the record evidence and the updates provided by MPCo in its Motion. While the April Order contained several conditions, only four created concern to MPCo, and ultimately, those were the primary issues raised on appeal: (1) $2.4 billion construction cost cap; (2) operational cost and performance parameters; (3) deferral of a decision on CWIP financing recovery; and (4) deferral of a decision on a prudence review schedule. In its Motion, the Company offered alternative conditions for the Commission's consideration that, if adopted, would allow the Company to finance and construct the Kemper Project, albeit on substantially less than the Company's ideal terms.

33. Following MPCo's Motion, the parties were permitted by Rule 12 of the Commission's Rules to file written responses to MPCo's Motion. Entegra, Calpine, Honorable Steven Chu, U.S. Secretary of Energy, Honorable Haley Barbour, Governor of Mississippi, and Mr. Queshaun Sudbury all submitted written comments concerning the Commission's April Order and/or MPCo's Motion. Although provided the opportunity, the Sierra Club chose not to submit a written response.

---

[27] *Id.* at 23.

[28] *Id.* at 23-24.

[29] *Id.*

34. The Commission also noticed and held two separate hearings on May 20, 2010, and May 26, 2010, for the purpose of discussing the Company's Motion and the written responses thereto.[30] All parties of record, including MPCo, received Notice of the May 20th Hearing by U.S. Mail,[31] which Notice was dated May 7, 2010. No action was taken to alter or amend the Commission's April Order at the May 20th Hearing. Notice of the May 26th Hearing was served upon all parties of record on May 17, 2010, by electronic transmission which is authorized by the Commission's Rules and was the accepted service procedure for all documents filed in the Kemper proceedings.[32] As indicated in the Commission's May Order, notice of the May 26th Hearing was also provided orally at the conclusion of the May 20th Hearing.

35. On May 26, 2010, the Commission issued its May Order in response to the Company's Motion and the other parties' responses thereto. The May Order specifically addressed many of the issues raised by MPCo's Motion and found that modifications to conditions contained in the April Order were warranted. The Commission found that the modifications were required to:

> provide a reasonable measure of certainty to the Company, ratepayers and investors that should allow the [Kemper] Project to go forward and will satisfy the public interest and the public convenience and necessity.[33]

36. Specifically, the Commission (1) imposed a construction cost cap of $2.88 billion, representing a 20% cap above MPCo's approved Kemper Project estimate; (2) removed the

---

[30] A hearing was held on May 14, 2010, for the sole purpose of considering the May 17th Order suspending Part XIII of the April Order.

[31] Under Commission Rule 6.113, notice of Commission hearings is deemed delivered when mailed.

[32] Administrative Filing Order (Apr. 15, 2009).

[33] May Order, p. 8.

financial incentive mechanism that would have rewarded the Company for cost underruns;[34] and (3) provided 100% CWIP financing cost recovery in years 2012, 2013 and 2014, while still requiring that MPCo establish annually that the recovery of financing costs is needed and in the public interest. Each of these issues was discussed in detail in the record as explained in Sections VI and VII of this Order. The Commission reiterated that an appropriate balance of risk and benefits of the Kemper Project between the Company and customers remained paramount and found that the conditions contained in the May Order achieved this objective.[35]

37. MPCo filed a Motion for Commission to Accept Petition, agreeing to the modified conditions imposed on the Kemper Project. On June 3, 2010, the Commission issued its Final Certificate Order.

E. Sierra Club Appeal

38. On June 16, 2010, the Commission's Final Certificate Order was appealed by Sierra Club to the Harrison County Chancery Court in Cause No. C2401-10-02580(1). On February 28, 2011, the Chancery Court issued its Judgment affirming the Final Certificate Order. The primary issues raised by the Sierra Club on appeal were whether the April and May Orders complied with Section 77-3-59, whether the Commission was arbitrary and capricious, whether the Commission's exercise of CWIP rate authority was supported by substantial evidence in the record, and whether the Commission's Rule permitting MPCo to submit certain rate impact information confidentially constituted reversible error.

---

[34] This provision could be significant for MPCo's customers. The Commission was made aware of the possibility that the Kemper Project would receive up to $1.2 billion in "early mover" benefits, cutting the cost of Kemper in half, if certain legislation currently proposed in Congress were passed. By removing this incentive mechanism, any such "early mover" benefits would flow to customers and not stockholders. *See* Phase Two Direct Testimony of F. Sherrell Brazzell, pp. 6-7 (Dec. 7, 2009).

[35] *See* May Order, p. 8.

39. On March 1, 2011, the Sierra Club subsequently appealed the Chancery Court's decision to the Mississippi Supreme Court. Following oral arguments, the Supreme Court issued an order on March 15, 2012, reversing the Harrison County Chancery Court's judgment and the Final Certificate Order, and remanding the case back to the Commission.[36] The Mississippi Supreme Court's decision did not speak to the merits of the decision, but only discussed whether the Order contained sufficient findings of fact to allow the Mississippi Supreme Court to determine the questions presented and the basis of the Commission's findings.[37]

III. PRESENT PROCEDURAL MOTIONS AND PROJECT STATUS

40. After the Mississippi Supreme Court issued its decision, the Sierra Club filed with the Commission a Motion for Status Conference Pending Remand, urging the Commission to halt construction of the Kemper Project and institute a full rehearing of the matter.[38] Relying almost exclusively on recent, lower-trending natural gas price forecasts, Sierra Club concludes that

> there is no question that there is evidence of significantly changed circumstances since Kemper was approved that supports a full hearing on the Kemper project and alternatives to the project. Further, any such proceeding must be carried out without any presumption that construction activities to date on Kemper were prudent or approved by the Commission as such.[39]

Simply put, Sierra Club urges this Commission to treat the Kemper Project as if *nothing* has occurred: no evidence has been heard, no certificate has issued, no construction has proceeded, no monitoring has been conducted.

---

[36] *Sierra Club v. Mississippi Pub. Serv. Comm'n*, 2011-CA-00350-SCT (¶ 2) (Miss. 2012).

[37] *Id.*

[38] Sierra Club Mot. for Status Conf., ¶ 7 (March 19, 2012).

[39] *Id.*

41. Similarly, Entegra filed with the Commission a Motion to Reopen Record for Additional Evidence and Prudence Review, asking the Commission to reconsider the economic feasibility and need for the Kemper Project in light of recent natural gas price forecasts.[40] Additionally, Entegra urges the Commission to review "the prudence of [MPCo] evaluations and decisions to continue construction of the Kemper project" in light of forecasted natural gas prices.[41] Entegra, an independent power producer, makes clear its willingness to sell capacity and energy to MPCo to satisfy any customer needs should the Kemper Project not proceed.[42]

42. Of course the timing of these motions is not coincidental to the Supreme Court's decision. Sierra Club and Entegra, given their respective interests, have seized upon the opportunity provided by the Mississippi Supreme Court to argue that the Kemper Project should be considered anew. The Commission is informed and acutely aware of recent natural gas price forecasts, the economics of the Kemper Project and the progress made in the plant's construction. Additionally, neither Sierra Club's nor Entegra's position on natural gas forecasts or alternative resource options adds anything to this Commission's preference for a 40 year baseload solution that secures fuel diversity and price stability. To the contrary, Sierra Club's and Entegra's litigation strategy continues to ignore that any credible natural gas option forces MPCo to rely heavily on natural gas and its corresponding volatility, a point on which the movants' attachments/evidence does not conflict.

43. Movants have not cited, and this Commission has not found, any statute, rule or case law that would require the Commission to reopen this matter to take more evidence and essentially re-litigate issues that have been fully addressed and of which this Commission is fully

[40] Entegra's Mot. to Reopen Record, p. 1 (March 29, 2012).

[41] *Id.*

[42] *Id.* at 5-6.

informed. In contrast, Mississippi Supreme Court precedent instructs that this Commission retains discretion to proceed as it determines appropriate. In *McGowan v. Miss. Oil & Gas Bd.*, the Court reviewed an order of the State Oil and Gas Board denying a permit to operate certain salt water disposal wells.[43] The Court noted that the Board had clearly denied the permits, but from the order, the Court could not discern why the Board had denied the permits.[44] The Court went on to explain that without sufficient findings and explanation the Court could not begin to determine whether the Board had acted arbitrarily and capriciously and therefore, could not perform its appellate function.[45] The Court concluded, as follows:

> We vacate the orders below and remand to the State Oil and Gas Board. The Board may reopen, a course we encourage (but do not require) in view of the improved procedures the Board has implemented since 1987. Or, the Board may proceed as all concerned may agree, or as may otherwise be appropriate. The Board may, if it deems it appropriate, stand by its prior orders, provided only that it make more than conclusory "written findings of fact and conclusions of law setting forth the reasons for the Board's decision." Nothing said here implies so much as a hint what the Board should do, so long as its further proceedings are not inconsistent with this opinion.[46]

44. The Commission interprets the Supreme Court's decision to merely require that the Commission's order granting the Kemper certificate contain sufficient findings and citations to the record to comply with the requirements of § 77-3-59. The proceedings conducted on remand are within the discretion of the Commission. As admitted by every stakeholder in this proceeding, including the Supreme Court, the Kemper record is extensive, and the Commission believes there is an overwhelming weight of credible evidence in the record to support the findings contained herein, making additional evidentiary proceedings unnecessary.

---

[43] *McGowan*, 604 So. 2d 312, 313 (Miss. 1992).

[44] *Id.* at 323-24.

[45] *Id.*

[46] *Id.* at 324-25; *see, supra,* n. 2.

45. As explained further below, the Commission finds it unnecessary to halt construction and reopen the Kemper Project to seek more evidence because the Commission has continued to monitor the project since initial approval; the Company has continued to report on the economic viability of the Project; the Commission has engaged in other proceedings highly relevant to this one; and the movants' positions offer nothing credible to address the Commission's preference for a 40 year solution that achieves fuel diversity and price stability.

A. PROJECT MONITORING

46. Following issuance of the certificate and requests for proposals, the Commission hired URS Corporation to act as the IM for the Commission.[47] URS is a nationally recognized engineering and construction firm that has extensive experience in the design, procurement, construction and operation of large utility projects, as well as mining experience. URS has hired several sub-contractors to assist them in monitoring the Kemper Project with specialties in accounting, environmental matters and ratemaking.

47. To assist in its statutory monitoring duties, the Staff hired another prominent engineering and construction firm, Burns and Roe, Inc. (BRE), to fill the IM role, which has also contracted with experts in the field of utility accounting and mining.[48]

48. All of the IMs have been involved monitoring various aspects of the Kemper Project, including engineering, land, construction, estimating, and contracting. URS maintains several full-time personnel on-site to monitor construction activities as they progress, and accountants maintain a full-time presence at MPCo's general office. URS produces a monthly written report to the Commission and consistently and routinely communicates with staff.

[47] The Commission retained URS on, or about, February 1, 2011.

[48] The Staff retained BRE on, our about January 18, 2011.

49. As of January 2012, engineering was 68% complete, with major equipment procurement nearly done at 88% complete. Actual construction of the plant itself stood at 17% complete, with various components nearing completion. For example, the Company had completed plant site clearing and grubbing activities, auger cast piling was 76% complete, caisson installation was complete, 50,795 cubic yards of concrete foundations had been poured, underground piping was 60% complete, electrical duct bank installation was 87% complete and structural steel erection was underway with 8% complete.

50. Pursuant to the Final Certificate Order, MPCo has made significant investments of time and money in the Kemper Project. For the period commencing upon the Company's receipt of the Final Certificate Order through February 2012, the Company has expended approximately $1.1 billion in connection with the construction of the Kemper Project. Approximately $1.5 billion of the total cost of the Kemper Project has been committed, meaning a cost that the Company has either already incurred or will be contractually obligated to pay.

51. The Project has been under construction for nearly two full years of a four year construction schedule. Currently, the design of the Project is approximately two thirds complete. All major construction contracts have been awarded and virtually all contractors have started significant work. Plant staffing and start-up activities are both well underway. MPCo is diligently negotiating final agreements for outstanding land and by-product needs. The lignite mine has received all necessary permits to commence construction and clearing and grading of the mine site is progressing. Along with the execution of key mining equipment contracts, MPCo expects construction of the dragline to start in the next several weeks. The plant's steam turbine is already on site, the gasifier is scheduled to begin delivery within the next six to eight weeks and the first gas turbine is due to be delivered this June. First fire of the combustion

turbines is expected to occur in only fifteen months. Literally thousands of design, construction and project activities are being performed by over 2,000 craft and other workers.

52. As required by the original orders, MPCo reports on the monthly progress of the Kemper plant. The reports are filed in this docket and are served on each original party to the Kemper proceeding. For example, the most recent filing reports on the various costs associated with each category, the certificated amount, the projected costs and any variance from the certificated amount.[49] According to the Company, the "[p]roject is on schedule and on budget. 72% of the Certified Plant Costs have been confirmed."[50]

53. In its March 2012 report, the Commission's IM generally agreed that "[a]ll construction activities are on schedule or ahead of schedule," with certain limited exceptions.[51] The IM, however, did raise concerns regarding the contingency. Specifically, the IM noted, as follows:

> The level of project contingency rundown is a concern that will require close monitoring. About 91% of the contingency has been allocated, while the overall project is only 26% complete (70% confirmed cost). The current forecast does not include adjustments for possible overruns based on historical trends or pending Change Orders. For example, the construction variance is $85 million with $573 million awarded (15% over plan to date). The forecast does not address budget impact if this adverse trend were to continue for the balance of construction. Instead, the forecast assumes the impact will not exceed available contingency. A special meeting is being scheduled in early May with all project stakeholders to discuss these concerns.[52]

The observation above exemplifies the dynamic interaction between the Company and IMs. The Commission IM noted a concern and has prompted the Company to address it.

[49] MPCo Monthly Project Status and Cost Report, Project Cost Summary attachment, p. 3, Table 3 (April 3, 2012).

[50] *Id.*, Executive Summary, p. 1.

[51] MPSC IM Monthly Report, Executive Summary attachment, p. 9 (March 2012).

[52] *Id.* at 5.

54. The presence of the IM allows this Commission to routinely assess the status of the Kemper Project. The ongoing monitoring negates the need to rely upon intervening parties to prompt a re-opening of the record to accept additional evidence. The regulatory regime presently in place does not require, or rely upon, parties to re-engage discovery, gather evidence, submit direct testimony and cross-examine witnesses. The Commission is a quasi-legislative body engaged in regulatory oversight, not a civil court deciding discreet rights between two parties.

55. The IMs have greater expertise, more resources and better access to the Kemper Project than either Sierra Club or Entegra, or any other party. The Commission, at any time it deems necessary, can require the Company to show cause that the Kemper Project remains in the public interest. The independent monitoring, monthly reporting and periodic economic analysis, if they are serving the intended purpose, should remove the need to re-open a case to accept new evidence or to issue a show cause order.

B. Continuing Economic Analysis

56. Given the monitoring and reporting requirements in place, the Commission has been, and continues to be, informed of the potential economic impact of lower natural gas prices on the Kemper Project. In its May 2011 Monthly Project Status and Cost Report, the Company attached a 12-cell table comparing the economics of the Kemper Project to a self-build natural gas combined cycle generating unit ("NGCC"), which represents the closest economic alternative to Kemper, at certain natural gas forecast and carbon constrained scenarios.[53] The assumptions and model were similar to those used by the Company in the Kemper proceedings,

[53] MPCo Monthly Project Status and Cost Report, Economic Analysis attachment, p. 9 Figure 1 (May 2, 2011).

although with updated information concerning load forecast, fuel forecast, inflation forecast and emissions allowance cost forecast.[54] The analysis showed that, if the Company were considering the matter anew, the Kemper Project would be the best economic choice in all the scenarios where future fuel prices are moderate or high (8 of the 12 scenarios), but an NGCC alternative is more economic in a future where natural gas prices remain low (4 of 12 scenarios).[55]

57. The May analysis confirms the Commission's original and continued understanding of the economics of the Kemper Project: it wins in a moderate and high fuel cost world and loses if fuel prices remain low for the long term. With natural gas comprising approximately 53% of MPCo's generating fleet[56] and with the traditional price volatility and potential future demand for natural gas, this Commission was and remains uncomfortable abandoning fuel diversity and the price stability offered by the Kemper Project. Without Kemper, MPCo's reliance on natural gas, and its associated price risks, rises dramatically.

58. MPCo filed a more recent economic analysis in February 2012, which offered more detail than the May 2011 economic analysis.[57] The February Economic Analysis again compared the Kemper Project with the most economical self-build NGCC in light of updated information, including natural gas forecasts and carbon constrained scenarios.[58] Specifically, the Company explained, as follows:

> Consistent with the Company's previous filings, analysis has been performed using a number of unique natural gas price forecasts that take into

---

[54] *Id.*

[55] *Id.*

[56] *See* Direct Testimony of Kimberly D. Flowers, p. 17 and Appendix I to Exhibit ____ (KDF-1) (Jan. 16, 2009).

[57] MPCo Monthly Project Status and Cost Report, Economic Analysis attachment, pp. 10-11 (Feb. 2, 2012).

[58] *Id.*

account supply (including shale), demand, global economic factors, and potential CO_2 emission impacts ($/ton).[59]

59. As expressed in 2014 Net Present Value ("NPV") of life cycle costs, the Kemper Project fared better than an NGCC with a 2017 in-service date in 8 of the 9 scenarios evaluated.[60] MPCo also produced a table that analyzed Kemper versus an NGCC if the costs already incurred (committed costs) in the Kemper project were attributed to an NGCC.[61] In this committed cost analysis, the Kemper Project had a lower net present value of life cycle costs in every scenario.[62]

60. The committed cost analysis is illustrative only, but it is relevant when considering the potential cost to company and ratepayer associated with cancelling or abandoning *any* construction project that was previously certificated. Assuming prudent decisions and actions, the analysis shows that as a project progresses the economics of cancelling the project in favor of an alternative get more difficult to justify.

61. This is common sense. For example, assume a public utility had received a certificate to build a natural gas plant and within six months of going into service natural gas prices spiked. If the economics of the plant were considered as if no construction had occurred, then the high prices of the day, if projected to persist, would require cancellation. The repercussions of such a regulatory policy are obvious: no public utility could plan for or risk constructing power plants. Granted, under the right circumstances cancellation could be justified (and most, if not all, of the costs might be passed to the utility), but the presence of the IMs helps

[59] *Id.* at 10.

[60] *Id.* at 11, Figure 2.

[61] *Id.* at 11, Figure 3.

[62] *Id.*

inform this Commission what those circumstances might be and when they might exist. The Kemper Project is not in that place.

C. Fuel Diversity and Price Stability

62. Halting construction of the Kemper Project to consider present natural gas prices would not address this Commission's preference for a 40 year baseload solution that yields fuel diversity and price stability. On the contrary, a natural gas solution would shift MPCo's generation to a 70% reliance on natural gas and bring with it corresponding price volatility. As explained in the following exchange, near absolute reliance on natural gas, particularly as a baseload asset, is unacceptable:

> COMMISSIONER BENTZ: Dr. Roach, I'm hearing a lot about this gas and 10 years. The question I need to ask, do you feel the utility company is being prudent to the ratepayers if they're 70 percent dependent on natural gas?
>
> DR. ROACH: That's -- you know, I haven't really addressed that. I think that is a worry. There's no doubt about it. Fuel diversity matters. I think I've been presuming, although it's not my place to presume, that you would not go forward, necessarily, with the gas option if it didn't offer you some fixed gas prices so you wouldn't face that risk, you wouldn't have that risk. So that's my presumption, but you'll make your decision.[63]

Additionally, Boston Pacific noted that without producing innovative fixed-price natural gas supply deals the natural gas industry would not be able "to secure a place for base load gas-fired electricity generation."[64] As noted herein, 10 year fixed gas contracts do not exist and indicative offers for such are not credible; therefore, natural gas options do not exist that would provide the sort of fuel diversity and price stability that this Commission seeks.[65]

---

[63] Phase Two Hearing Transcript, pp. 1604-05.

[64] Report of the Independent Evaluator, p. 24 (Jan. 25, 2010).

[65] For a full discussion *see, infra*, part V.D. and E.

63. The Commission finds that fuel diversity matters, particularly because fuel price stability matters. The Kemper Project offers both, giving MPCo a third fuel source for its generation fleet and utilizing a lignite resource owned by the Company and mined at the mouth of the Kemper plant. Lignite will be subject to neither shifting transportation costs nor market pressure, thereby offering near price certainty and transparency.[66]

64. In addition, the Commission's decision to not adopt any one natural gas price forecast as most probable also supports the Commission's decision not to reopen the record. Both Sierra Club and Entegra have requested we do so, primarily based upon their belief that natural gas prices will remain at historic lows far into the future. In essence, the movants are requesting the Commission adopt the low-end of the natural gas forecast in the record, which, for reasons stated in this Order, the Commission finds unwise and declines to do.

65. Because Sierra Club's and Entegra's suggestions offer nothing to further address fuel diversity and price stability, the Commission finds that their respective motions lack merit.

D. THE DANIEL SCRUBBER PROJECT

66. As noted above and continued below, the Commission is aware of natural gas prices and the importance of fuel diversity and price stability. The monitoring and reporting of the Kemper Project is not the only matter before this Commission or from which the Commission draws and develops its understanding of the utility industry. Natural gas forecasts were featured prominently in MPCo's petition to construct and install "scrubbers" on the coal units at Plant Daniel ("the Scrubber Project") to comply with regulations issued by the U.S. Environmental Protection Agency.[67]

---

[66] *See, e.g.*, Phase Two Hearing Transcript, pp. 1803-04.

[67] MPSC Docket No. 2010-UA-279, Final Certificate Order (April 3, 2012).

67. On July 22, 2010, MPCo filed its petition for a certificate to construct the Scrubber Project.[68] The Sierra Club intervened as a party, and the Public Utilities Staff ("the Staff"), although not advocating a particular outcome, actively participated in the case and offered expert analysis and testimony by Economic Insights, Inc. ("EI").[69] Although discovery was completed and a full hearing was held on January 25, 2011, the Commission decided to delay its order until the EPA issued its final rule, which was eventually issued on December 21, 2011.[70] On October 25, 2011, the Sierra Club, which had not previously offered expert testimony, moved to re-open the record to accept evidence related to lower natural gas price forecasts, which the Commission granted on January 11, 2012.[71]

68. The Staff, MPCo and Sierra Club offered supplemental evidence, and the Commission held a supplemental evidentiary hearing on March 14, 2012.[72] In its Final Order approving the certificate to construct the Scrubber Project, the Commission focused on natural gas forecasts, the volatility of natural gas and the importance of fuel diversity and price stability.[73] The Commission considered Sierra Club's evidence of potentially lower natural gas prices, as well as Staff's expert's admonition to exercise caution when considering natural gas price forecasts and to consider the strategic benefits of fuel diversity.[74]

69. The Commission highlights the following portion of its Final Order regarding the Scrubber Project:

---

[68] *Id.* at ¶ 10.

[69] *Id.* at ¶¶ 12-13.

[70] *Id.* at ¶¶ 15-17.

[71] *Id.* at ¶¶ 16-18.

[72] *Id.* at ¶¶ 18-20.

[73] *Id.* at ¶¶ 29-50, 55-59.

[74] *Id.* at ¶¶ 32-50.

> The Sierra Club's supplemental testimony offered that the Company's natural gas forecasts were too high and advocated for the incorporation of recently released forecasts generated from the Energy Information Agency ("EIA"). . . .
>
> EI [Staff's expert] also offered supplemental testimony taking issue with aspects of Sierra Club's evidence regarding natural gas prices. EI noted that, while the EIA's 2011 forecast was lower than the 2010 "Low EIA" they had asked MPCo to analyze, the difference between the two was not great. EI went on to testify about the 2010 EIA high shale gas case (EIA Low 2010 case), the EIA 2011 Reference case, and the 2012 Early Release Reference case. EI noted that the high shale gas scenario examined by MPCo was actually lower than the EIA 2010 forecast and that the high shale gas scenario considered was comparable to the EIA early 2011 reference case. EI went on to state that present natural gas forecasts should be viewed with caution due to factors such as higher labor costs as the economy improves, shuttering of production of shale gas wells, public anxiety over fracking and the possibility of future regulation, and a bias among forecasters to allow present conditions to skew forecasts. For example, when prices are low EIA tends to forecast about 7% lower than actual future prices.
>
> Sierra Club noted that the Low gas price forecast submitted by the Company in its most recent analysis is essentially the same as the 2010 Low EIA forecast that EI requested MPCo to consider. Additionally, MPCo significantly reduced its High and Moderate estimates from their prior forecasts.[75]

Not surprisingly, this Commission found "that the conflicting evidence on natural gas forecasts points out the difficulty in predicting long-term future natural gas prices."[76] As exemplified by the above, the Commission is well-aware of the issues and considerations associated with natural gas price forecasts.

70. After thorough review, the Commission found that "MPCo has submitted a reasonable range of possible gas and carbon constrained scenarios for considering the Scrubber Project. Although the Sierra Club would like to see certain scenarios discarded or added, the

[75] *Id.* at ¶¶ 43, 47-49 (internal footnotes omitted).

[76] *Id.* at ¶ 57.

Commission finds that the gas projections offered by MPCo provide a reasonable range of possibilities . . . ."[77] Finding in favor of fuel diversity and price stability, the Commission granted a certificate to MPCo to construct and install the Scrubber Project.

71. At least two significant parallels or connections exists between the Scrubber Project docket and the Kemper Project docket that further undermines Sierra Club's and Entegra's pleas to re-open the Kemper docket and halt project construction. First, several important issues or concerns permeated both the Kemper Project and the Scrubber Project, such as overreliance on natural gas, price volatility, fuel diversity, price stability, the value of baseload generation, and the uncertainty surrounding natural gas forecasts. For example, concern over the impact to natural gas of potential environmental issues related to "fracking" existed in both proceedings[78], as did legitimate criticism of EIA natural gas forecasts.[79] The point being, what was relevant in the Kemper proceedings was relevant in the recent Daniel Scrubber proceeding; and the Commission has made consistent and informed decisions on these matters.

72. Second, the resource planning and basic methodology and inputs that were used and approved in the economic analysis of the Kemper Project were the same ones used and approved for the Scrubber Project.[80] Additionally, the economic analysis that emerged from the Scrubber Project is the same one MPCo recently used to compare the life cycle costs of the Kemper Project versus an NGCC alternative.[81]

---

[77] *Id.* at ¶ 50.

[78] Transcript of Proceedings Hearing on Need (hereinafter "Phase One Hearing Transcript"), pp. 305-06.

[79] *See, e.g.*, Phase Two Hearing Transcript, pp. 1647-48.

[80] *Id.* at ¶¶ 29, 33, 41-46.

[81] *See* MPCo Monthly Project Status and Cost Report, Economic Analysis attachment, pp. 10-11 (Feb. 2, 2012).

73. Sierra Club's and Entegra's desire to once again litigate natural gas forecasts and resource options fails to address the Commission's policy preference for a 40 year solution that will provide fuel diversity and price stability as a counterweight against overreliance on natural gas and the corresponding volatility. The motions made by Entegra and Sierra Club attempt to once again place *their* singular interests before this Commission so that they can again attempt to make *their own* cases against the Kemper Project. The Commission's charge, however, is broader than the interests of Entegra and the Sierra Club. The Commission must pursue the public interest, and the Commission finds that halting construction on the Kemper Project and re-opening the case for another round of discovery and hearing, to take and consider evidence with which this Commission is already familiar, is not in the public interest.

74. The reporting and monitoring established by the Commission serves to inform this Commission of the status and viability of the Kemper Project. If at any time the Commission's investigation and monitoring reveals a need to order MPCo to account for the Kemper Project in a formal hearing, the Commission may so order, but now is not the time. Consequently, the Commission denies Entegra's Motion to Re-Open and the Sierra Club's Motion for Status Conference.

75. As exemplified above, no hearing is necessary for this Commission to consider and decide the pending procedural motions, nor would such a proceeding aid this Commission or further the public interest. Having dispensed with the pending motions, the Commission turns to the evidence of record before it, and conducts its analysis and renders a decision thereon.

IV. LEGAL MATTERS

A. APPLICABLE LAW; STATUTORY FRAMEWORK FOR CERTIFICATES

74. Sections 77-3-11, 77-3-13, and 77-3-14, prescribe the statutory requirements governing applications for certificates of public convenience and necessity made to the Commission. In addition, RP 7 of the Commission's Rules gives effect to these sections by prescribing the specific filing requirements that must be met by any utility seeking a certificate. Under § 77-3-14(1):

> no public utility or other person shall begin the construction of any facility for the generation and transmission of electricity to be directly or indirectly used for the furnishing of public utility service in this state . . . without first obtaining from the commission a certificate that the public convenience and necessity requires, or will require, such construction.

75. When determining whether to grant such certificate, the Commission will:

> take into account the utility's arrangements with other electric utilities for the interchange of power, pooling of plant, purchase of power and other methods for providing reliable, efficient and economical electric service.[82]

As a further condition to the issuance of a certificate, the Commission must approve the estimated construction costs for the proposed facility.[83]

76. In light of the issues raised on appeal by Sierra Club and in light of our re-examination of the record in this proceeding, the Commission finds that further explanation of the certification process and framework is warranted to put the Commission's original decision to approve the Kemper Project in the proper context for the parties and for any reviewing court. The certification process established by the Mississippi Legislature under the Act requires MPCo to apply for a certificate *before* commencing construction on any new generating facility. In other words, MPCo must apply for the certificate as the first step in the certification process. In

[82] MISS. CODE ANN. § 77-3-14(3) (Rev. 2011).

[83] MISS. CODE ANN. § 77-3-14(4) (Rev. 2011).

order to comply with the filing requirements established by the Commission, the certificate application must include an estimate of the construction costs for the proposed facility. Typically, however, those estimates are preliminary in nature, because the detailed design and procurement of materials for utility assets is very expensive and without authority to proceed with the project from the Commission, the utility cannot be reasonably assured of cost recovery for such activities without a certificate.

77. In this case, the Commission and Staff were provided more detail and analysis regarding the design and cost estimates for the Kemper Project than is ordinarily presented for other certificate applications. In 2006, the Company applied for and was granted limited authority as part of its generation screening and evaluation activities to prepare a Front End Engineering and Design (FEED) study for the Kemper Project. Therefore, while the Commission still has some concerns about the Company's estimates and the fact that only a small portion of the detailed design and procurement had been done as of June 3, 2010, we do acknowledge that such uncertainties are primarily a function of the certificate framework under which the Company and the Commission operate.

78. Ultimately, the Commission must issue an order that meets the requirements of § 77-3-59 by making findings that are supported by substantial evidence presented in the record and "in sufficient detail to enable the court on appeal to determine the controverted questions presented, and the basis of the commission's conclusion."[84]

79. Section 77-3-13(3) provides that the Commission:

> may attach to the exercise of the rights granted by the certificate such reasonable terms and conditions as to time or otherwise as, in

[84] MISS. CODE ANN. § 77-3-59 (Rev. 2011).

> its judgment, the public convenience, necessity and protection may require . . . .[85]

This provision provides the authority for the Commission's placement of conditions upon the certificate granted.

B. BASELOAD ACT

80. Section 77-3-101 *et seq*., also known as the Baseload Act, prescribes alternative methods of cost recovery for certain baseload generation. By enacting the Baseload Act, the Mississippi Legislature created a separate, entirely new article of the Mississippi Code that establishes the policy of the State of Mississippi favoring baseload generation and establishes an alternate method of cost recovery for qualifying baseload generating facilities. Through its passage of the Baseload Act, the Legislature has determined it to be in the public interest for the State of Mississippi to promote and foster the construction of baseload electric generating facilities by public utilities.[86] The Baseload Act is designed to facilitate Mississippi electric public utilities' ability to finance and construct baseload generation by authorizing the Commission, at its discretion and when it is in the best interest of customers to do so, to utilize an alternate method of recovery of financing costs during construction for qualifying baseload generation.

81. Typically, in regulatory orders approving facilities for a utility, the Commission approves an estimate, the Company constructs the facility, and the utility seeks rate recovery for the facility following construction. At that time, the Commission is able to compare the actual costs of the facility to the estimated costs of the facility and determine whether the costs or any variances in the costs were prudent. Given the magnitude of the project and MPCo's request for

[85] MISS. CODE ANN. § 77-3-13(3) (Rev. 2011).

[86] *See* MISS. CODE ANN. § 77-3-101 (Rev. 2009).

relief under the Baseload Act, the Commission determined that it would be appropriate to focus on the potential risks to both the Company and the customers and develop conditions, as described below, to appropriately balance such risks.

82. In addition to its broad declaration of public policy favoring the development of baseload generating capacity, the Baseload Act addresses five specific issues regarding the treatment of the costs associated with baseload generating facilities and the inclusion of such costs in the rates of public utilities: (i) § 77-3-103 defines the types of generating facilities that qualify for consideration by the Commission under the Baseload Act and the pre-construction costs that are eligible for recovery under the Baseload Act; (ii) § 77-3-105(1)(a) empowers the Commission, subject to findings of prudence, to include certain types of costs, including without limitation CWIP, in rate base and rates of a public utility during construction; (iii) § 77-3-105(1)(b) empowers the Commission to allow the public utility to earn a just and reasonable return on the unrecovered balance of qualifying costs; (iv) § 77-3-105(1)(c) empowers the Commission to establish and approve the mechanisms for rate recovery of qualifying costs; and (v) § 77-3-105(1)(e) sets forth the rights and obligations of the public utility and the authority of the Commission in the event a generating plant approved for alternative cost recovery treatment under the Baseload Act is canceled.

83. The Commission takes notice that the Baseload Act is enabling and not mandatory. Any decision by the Commission to exercise its discretionary authority under the Baseload Act must include a finding that the public interest requires the implementation of the alternative recovery methods authorized under § 77-3-105 of the Baseload Act. MPCo has requested that the Commission find that the application of the Baseload Act is in the public

interest, and that we exercise our full statutory authority implementing the provisions of the Baseload Act.

84. Several parties argued during the course of this proceeding that MPCo's application constituted a "rate filing" under § 77-3-37, and that MPCo must comply with the provisions of that section for the implementation of the Baseload Act and for any changes in rates approved under the Baseload Act. The parties submitted multiple legal briefs on these issues, and the Commission heard oral argument on the issues during the proceeding. After carefully reviewing the legal briefs on these issues, the Commission finds that the provisions of § 77-3-37 are not applicable to MPCo's certificate request in this proceeding, because MPCo's Certificate Filing has not made a request to change customer rates. In fact, all rate matters related to the Kemper Project are being addressed in a separate rate proceeding, Docket No. 2011-UN-135, which is currently pending before the Commission.

C. Jurisdiction and Sufficiency of the Filing

85. The Commission finds that it has jurisdiction over the parties and subject matter in this proceeding.

86. The Commission finds that MPCo has adequately complied with the requirements of the Act and the Rules regarding requests for Certificates of Public Convenience and Necessity and has provided all of the information relevant to and necessary for the Commission to evaluate its Certificate Filing and to support our Order in this Docket. Therefore, for good cause shown, the Commission hereby waives each and every other filing requirement that may be prescribed by the Commission's Rules.

V. EVALUATION AND APPROVAL OF THE KEMPER PROJECT

A. Petitioner's Characteristics.

87. MPCo is a public utility as defined in § 77-3-3(d)(i) and is engaged in the business of providing electric service to and for the public for compensation in twenty-three (23) counties of southeastern Mississippi, having its principal place of business at Gulfport, Mississippi.

88. MPCo holds a Certificate of Public Convenience and Necessity issued by the Commission in Docket No. U-99, as supplemented from time to time, authorizing its operations in certain areas in the twenty-three (23) counties of southeastern Mississippi, and is rendering service in accordance with its service rules and regulations and in accordance with schedules of rates and charges, all of which are a part of its tariff that has been previously approved by order of the Commission.

89. MPCo is a Mississippi corporation. A copy of its corporate charter, articles of incorporation, the names and addresses of its board of directors and officers, the name of all persons owning fifteen percent (15%) or more of its stock, and a copy of its current balance sheet and income statement are on file with the Commission and are hereby incorporated by reference.

90. MPCo has an obligation under the Act to provide reliable electric service to its customers at the lowest reasonable costs. Planning for generation requirements necessary to serve its customers is an essential part of fulfilling that obligation. Currently, MPCo serves approximately 186,000 retail customers in 123 municipalities and unincorporated communities in southeastern Mississippi.

91. MPCo also provides full-requirements electric service at wholesale to South Mississippi Electric Power Association (SMEPA) at certain wholesale delivery points on behalf of Coast Electric Power Association, Singing River Electric Power Association, Dixie Electric Power Association, Southern Pine Electric Power Association, and Pearl River Valley Electric

Power Association. In addition, MPCo provides full-requirements electric service at wholesale to East Mississippi Electric Power Association at certain wholesale delivery points, and to the City of Collins, Mississippi. Through these wholesale electric service contracts, MPCo indirectly provides full requirements for capacity and energy to approximately 175,000 additional customers in Mississippi.

92. Currently, MPCo owns or controls approximately 3,309 MW of electric capacity available to serve its jurisdictional retail and territorial wholesale customers in Mississippi, all of which was provided to the Commission in detail in the Company's filing.[87] MPCo's current available generating capacity includes 445 MW of aging natural gas-fired steam generation, 1,492 MW of coal-fired steam generation, 1,054 MW combined-cycle natural gas-fired generation, 130 MW of gas-fired cogeneration (dedicated to the Chevron Refinery in Pascagoula, Mississippi), and 65 MW of gas-fired combustion turbine generation.[88] A portion of MPCo's capacity is owned under joint ownership arrangements with Alabama Power Company (Greene County Units 1 and 2) and Gulf Power Company (Plant Daniel Units 1 and 2), and other portions are provided through active Demand Side Options, such as interruptible and stand-by generation contracts with retail customers approved by the Commission.[89] "Approximately 47% of [MPCo's] generating capacity uses coal as the primary fuel, and approximately 53% uses natural gas as the primary fuel."[90]

93. In addition, MPCo is a member of a pooling arrangement within the Southern electric system (SES), which consists of MPCo, Alabama Power Company, Georgia Power

---

[87] *See* Direct Testimony of Kimberly D. Flowers, p. 17 (Jan. 16, 2009).

[88] Appendix I to Exhibit___(KDF-1) to Direct Testimony of Kimberly D. Flowers (Jan. 16, 2009).

[89] *See* Direct Testimony of Kimberly D. Flowers, p. 16-17 (Jan. 16, 2009).

[90] *Id.* at 17.

Company, Gulf Power Company, and Southern Power Company (collectively the Southern Operating Companies).[91] The Southern Operating Companies function as a single, integrated, public utility system through adherence to the Southern Company Intercompany Interchange Contract (IIC), an agreement approved by and on file with the Federal Energy Regulatory Commission (FERC).[92] The SES, through the IIC, operates its power pool using traditional concepts of economic dispatch.[93] The SES power pool is a coordinated pool, not a centralized pool.[94] While all of the generating facilities of each Southern Operating Company are committed to a centralized economic dispatch, each individual Southern Operating Company, including MPCo, retains the responsibility for providing the generation and transmission facilities necessary to meet the requirements of its customers.[95] Stated differently, MPCo is responsible for meeting the capacity and energy needs of its own customers, and cannot rely upon the power pool for that purpose.

94. MPCo is authorized by Mississippi law to exercise the right of eminent domain to acquire the easements and property rights reasonably necessary for the construction, operation, and maintenance of its electric power works, lines, substations, natural gas pipelines, CO_2 pipelines, water pipelines and related facilities used and useful in connection with the Company's service to its customers.[96]

B. MPCo's Generation Screening and Evaluation Activities

[91] *See* Direct Testimony of Garey C. Rozier, p. 4 (Jan. 16, 2009).

[92] *Id.*

[93] *Id.* at 5.

[94] *Id.* at 4.

[95] *Id.* at 6.

[96] MISS. CODE ANN. §§ 11-27-41, 11-27-45 & 11-27-47 (Rev. 2011).

95. In 2006, the Company's internal analysis identified a need for new capacity beginning in the 2013 time frame, and it undertook an investigation of the alternatives available to meet that need. On November 7, 2006, in Docket No. 2006-UN-0581, MPCo filed its Notice Requesting Approval of Accounting Treatment for Generation Resource Planning, Evaluation and Screening Activities requesting approval by the Commission of the Company's proposed treatment of the costs associated with its undertaking generation resource planning, evaluation, and screening activities.

96. On December 21, 2006, the Commission issued an order finding that the Company's process of periodically and thoroughly screening and planning for new generation facilities was prudent, reasonable and necessary, and in the public interest. Further, the Commission authorized the Company to create and recognize a regulatory asset to charge the costs associated with this generation evaluation and decision. By subsequent orders of the Commission on December 28, 2007, and April 6, 2009, the Commission amended its previous orders and instructed the Company to continue to charge all costs associated with generation screening and evaluation to the regulatory asset and deferred the disposition of the regulatory asset.

97. In its April 6, 2009, order, the Commission also requested that the Staff continue its on-going investigation of the prudence of MPCo's pre-construction expenditures in conjunction with the Staff's review of the Company's Certificate Filing in this Docket. The Commission further found that following the completion of the Staff's review and the submission of a report to the Commission and MPCo, the Commission would hold hearings, if necessary, and make findings on the prudence of such pre-construction costs in this Docket No. 2009-UA-14. Finally, the Commission ordered MPCo to continue to charge all of pre-

construction costs to the regulatory asset until the Commission makes findings and determinations as to the recovery of the Company's prudent expenditures in this Docket.

98. During the screening process, the Company identified two primary risks associated with the existing fleet that will challenge MPCo's ability to serve customers reliably and at the lowest reasonable cost over the long-term—environmental compliance and fuel volatility.[97] First, the parties in this proceeding and the Commission itself have all determined that some type of carbon legislation or regulation is likely in the near future.[98] As carbon compliance cost increases, coal unit retirements sharply increase MPCo's "reliability" need for new baseload capacity. Recent developments in other environmental regulations for conventional emissions (i.e. mercury, NO_x, SO2 and particulates), indicated to MPCo that control equipment rather than allowances, will be required for continued operations of pulverized coal plants, and will likely need to be installed by November 2014.[99] Second, recent developments in the natural gas and coal markets and the demonstrated volatility of those markets elevated the Company's concern regarding any increasing degree of reliance on natural gas and, to a lesser degree, high rank coals.[100] All of the experts who testified in this proceeding agree that volatility of natural gas prices will continue and must be considered when making long-term resource decisions.[101]

99. Given the range of MPCo's need for new capacity established by the order in Phase One and recognizing the Company's legal obligation to provide reliable and adequate

[97] *See* Direct Testimony of Kimberly D. Flowers, pp. 6-7, 9-12, 18-19 (Jan. 16, 2009).

[98] *See* Phase One Hearing Transcript, pp. 46, 61, 460, 467, 552-553.

[99] *See* Phase Two Direct Testimony of Kimberly D. Flowers, p. 6 (Dec. 7, 2009).

[100] *Id.* at 3.

[101] *See* Phase One Hearing Transcript, pp. 75, 112, 134, 358.

service to its customers, the Commission confirms its finding that it was prudent for the Company to take steps to meet its capacity need, as it did, so that both the Company and the Commission can reasonably ensure that an adequate supply of capacity exists in the future to serve MPCo's territorial load. The Commission recognizes that a utility's capacity and energy needs are typically met from one or a combination of resource alternatives that fit into three categories: (i) DSMs and energy efficiency (EE) programs; (ii) wholesale capacity and energy purchases; and (iii) self-build generation.

100. As we found in Phase One, MPCo has a well-established and effective program for identifying and evaluating DSM and EE programs.[102] They are continually evaluated by the Company and the benefits of these programs are included in the Company's annual Load and Energy Forecast and in the Company's regular integrated resource planning process.[103] The evidence presented by the Company in its filing and at the hearings demonstrates that, despite MPCo's numerous cost-effective current and planned DSM programs, those programs are inadequate to fully meet MPCo's needs.[104] The Company's evidence demonstrated that the Company evaluated the remaining two categories of alternatives in the following manner:

First, MPCo selected, screened and evaluated the various self-build alternatives available to meet the identified need in a prudent and cost-effective manner. This process was approved by orders of the Commission in Docket No. 2006-UN-0581. To determine the best alternative for meeting the generation needs identified, MPCo, with the assistance of Southern Company Services (SCS), began by identifying the types of generation technology that were

---

[102] Order Finding Need for Generating Capacity and Energy, p. 14 (Nov. 9, 2009).

[103] Exhibit___(DFS-1) to Phase Two Direct Testimony of David F. Schmidt and Garey C. Rozier, pp. 35-38 (Dec. 7, 2009).

[104] *Id.* at 7.

reasonably available in the relevant time frame. A multitude of qualitative and quantitative factors were utilized to determine whether a new resource or a market solution best fits MPCo's need. Comparisons among the various alternatives considered issues such as technology availability, reserve margin levels, generation mix, fuel diversity, capital spending, on-going O&M costs, environmental issues, risk management, construction lead times, and the availability of financial incentives.[105]

Second, a detailed economic analysis was conducted by the Company to compare the cost of the self-build alternatives identified in the screening process to determine the overall least-cost option based upon the net present value of revenue requirements over a forty-year period. All alternatives were scaled to the same net summer peak capacity so that each alternative could be compared on a dollar per kW basis. The forty-year revenue requirements were then discounted at MPCo's after-tax weighted average cost of capital to calculate a cumulative net present value for each alternative. The Company testified that its economic evaluation and analysis indicated that the Project is the best self-build generation resource alternative available to meet MPCo's identified need in 2014, and is in the overall best interest of customers.[106]

Third, throughout the screening and evaluation process, MPCo issued two separate Invitations for Indicative Proposals of Solid Fuel-Fired Generating Capacity in 2007 and 2008, to test the wholesale market for viable generation alternatives that could adequately meet MPCo's need and that might compare favorably to the Kemper County IGCC self-build

[105] *See* Phase Two Direct Testimony of F. Sherrell Brazzell, pp. 3-4 (Dec. 7, 2009).

[106] *See* Phase Two Hearing Transcript, pp. 2030-31.

alternative.[107] The conforming proposals from both invitations were compared to the Company's Kemper County IGCC Project and an economic analysis similar to that used to compare the Company's other self-build alternatives was performed. MPCo concluded that the IGCC self-build alternative was the most cost-effective solid-fuel option available, and that no wholesale market offerings provided better value.[108] Evidence presented by intervenors and by Dr. Roach at the hearings in Phase One suggested that MPCo's Invitations for Indicative Proposals were too limiting and that they indicated MPCo's bias for solid-fuel baseload capacity to the exclusion of natural gas options available in the wholesale market.[109] Based upon all of the evidence presented regarding the requests for indicative proposals, the Commission determined that it was prudent and in the public interest to allow market participants to submit resource alternatives in Phase Two pursuant to a Commission-sanctioned and monitored process that included the use of an independent evaluator. While MPCo questioned its usefulness, no party formally objected to the implementation of this additional market analysis. The Commission's findings of fact and conclusions of law regarding the market solicitation process, the resource alternatives presented, and the analyses of those alternatives are addressed later in this Order.

C. DESCRIPTION OF THE KEMPER COUNTY IGCC PROJECT

101. According to the testimony of Kimberly D. Flowers, MPCo's Vice President and Senior Production Officer, and Thomas O. Anderson, MPCo's Vice President Generation Development, the Kemper Project consists of: (i) a lignite-fueled two-on-one (2-on-1) integrated gasification combined-cycle baseload electric generating facility with a net summer output capacity of 582 MW (Plant); (ii) environmental equipment for the reduction of various

[107] Direct Testimony of Garey C. Rozier, p. 9 (Jan. 16, 2009).

[108] *Id.*

[109] *See* Phase One Hearing Transcript, pp. 726-728, 755-756, 767-768.

emissions from the Plant, including without limitation, equipment and facilities for the capture of approximately 65% of the CO_2 emissions from the Plant; (iii) approximately sixty miles of electric transmission lines with voltages varying from 115 kV to 230 kV; (iv) three new electric transmission substations; (v) approximately five miles of natural gas transportation facilities to accommodate natural gas deliveries to the Plant; (vi) approximately 30 miles of water transportation facilities to accommodate the delivery of the City of Meridian treated wastewater to the Plant site for the Plant's cooling and process water needs; (vii) mineral leases, mining facilities and equipment and all related facilities needed to mine lignite; (viii) the option to own the approximately 55 miles of CO_2 pipeline necessary to transport CO_2 from the Plant boundary to oil fields suitable for EOR; and (ix) the related facilities, rights-of-way, and other rights necessary for the efficient and effective construction, acquisition, operation, repair, and maintenance of the Plant (Kemper Project).[110]

102. The Project has a designed net summer peak capacity of 582 MW.[111] Electrical power will be generated at 18 kV by the gas and steam turbine generators.[112] The generators have dedicated step-up transformers to increase voltage to 230 kV.[113] The Plant capacity includes 522 MW of lignite-fueled base capacity and 60 MW of duct-fired peaking capacity fueled by natural gas.[114]

103. The Project consists of two major system classifications: a gasification island and a combined cycle generating unit. The Plant will incorporate the air-blown Transport Integrated

---

[110] *See* Direct Testimony of Kimberly D. Flowers, pp. 35-36 (Jan. 16, 2009); Phase Two Direct Testimony of Thomas O. Anderson, pp. 5-6 (Dec. 7, 2009)

[111] Phase Two Direct Testimony of Thomas O. Anderson, p. 5 (Dec. 7, 2009).

[112] Direct Testimony of Kimberly D. Flowers, pp. 35-36 (Jan. 16, 2009)

[113] *Id.*

[114] Phase Two Direct Testimony of Thomas O. Anderson, p. 5 (Dec. 7, 2009).

Gasification (TRIG™) technology jointly developed by Southern Company, Kellogg Brown & Root, LLC (KBR), and the U.S. Department of Energy (DOE).[115] The Plant will be fueled primarily by lignite mined in Kemper County, Mississippi.[116] The lignite will be converted to synthesis gas (syngas) by the TRIG™ gasifier for use in a 2-on-1 combined cycle generating unit.[117]

104. Randall E. Rush, General Manager Gasification Technology, SCS and Dr. Larry S. Monroe, Senior Research Consultant for SCS, testified that the TRIG™ technology was specifically developed for power production, and is based upon the well-known Fluid Catalytic Cracking (FCC) technology utilized in the petroleum industry for nearly 70 years. The witnesses testified that the primary benefit of the TRIG™ design is its unique capability to economically and effectively use lower rank, abundant, and low and stable priced fuels such as lignite and sub-bituminous coals.[118] According to Mr. Rush and the documentary evidence presented by the Company, the TRIG™ technology has been developed and tested at the Power Systems Development Facility (PSDF) in Wilsonville, Alabama, over the course of 15 years, through a collaborative effort among Southern Company, KBR, and DOE.[119] The Company witnesses testified that Mississippi lignite has been tested successfully at PSDF over the course of many hours and that all of the units involved in the syngas production process worked with a high

[115] Exhibit___(TOA-1) to Phase Two Direct Testimony of Thomas O. Anderson, p. 20 (Dec. 7, 2009).

[116] Phase Two Direct Testimony of Thomas O. Anderson, p. 20 (Dec. 7, 2009).

[117] Direct Testimony of Kimberly D. Flowers, p. 35 (Jan. 16, 2009).

[118] *See* Phase Two Direct Testimony of Dr. Larry S. Monroe and Randall E. Rush, pp. 5, 7 (Dec. 7, 2009).

[119] *Id.* at 4.

degree of reliability.[120] In total, the Company has run three separate test campaigns using Mississippi lignite, which totaled 1,795 hours of TRIG™ gasifier operation.[121]

105. The Plant is located near the unincorporated community of Liberty in Kemper County, Mississippi, and is situated wholly within the certificated service area of East Mississippi Electric Power Association. A more detailed description of the Plant site is included with the Certificate Filing and is incorporated herein by reference. The Plant site is comprised of approximately 1,750 acres, which includes sufficient land for the Plant and all associated facilities and equipment.[122] At the time of the Phase Two Hearings, MPCo owned approximately 770 acres of the site and possessed options to purchase the remaining acreage needed.[123]

106. The Project will utilize lignite from the Damascus Reserve. Mr. Anderson testified that the Company will own and develop the mine, all associated mineral interests, and all of the equipment and facilities related to the mine and mining operations.[124] The Company undertook an evaluation of competent mining companies with lignite experience and selected North American Coal (NAC) to perform all mining operations on behalf of MPCo, including development and permitting of the mine.[125] According to the Company witnesses, NAC has significant experience and expertise in the development and operation of lignite mines and in the development and operation of lignite delivery systems for power generation projects.[126] For this Project, NAC has formed a subsidiary, Liberty Fuels, LLC, to perform the mining services for

---

[120] *Id.* at 7-8.

[121] *See* Phase II Direct Testimony of Thomas O. Anderson, p. 10 (Dec. 7, 2009).

[122] *Id.* at 6.

[123] *Id.*

[124] *Id.* at 20.

[125] *Id.*

[126] *Id.*

MPCo. Under this "management fee" mining arrangement with Liberty Fuels, LLC, MPCo will pay the costs associated with all mining activities and will pay a management fee based upon the amount of lignite actually delivered (as measured in mmBtu) to the Plant.[127] As of the Company's December 7, 2009, Third Supplemental Filing, MPCo had 72 mineral leases in place covering 8,820 surface acres.[128] The estimated cost of the lignite over the forty year life of the Project was included in Mr. Anderson's testimony and exhibits. Due to the confidential and competitive nature of the pricing information it is not being restated in this Order.

107. The Project has been designed with technology to reduce emissions that result in full compliance with the Clean Air Act and all applicable regulations promulgated thereunder to date.[129] The syngas cleanup processes planned for the Project are an integral part of the overall gasification process design, and are included as a means to reduce stack emissions. The emission rates expected by utilizing these processes represent the best available air pollution control technologies and will allow MPCo to permit the Plant in accordance with all federal and state ambient air quality standards.[130]

108. As proposed by the Company and based upon the evidence presented, the Plant will be designed to capture approximately 65% of its CO_2 output.[131] This level of carbon capture makes the Project's CO_2 emissions equivalent to similarly sized natural gas fired generation.[132] The Commission found in its Phase One Order that some type of climate change legislation

---

[127] *Id.*

[128] *Id.*

[129] Exhibit__(TOA-1) Appendix A to Phase Two Direct Testimony of Thomas O. Anderson, p. 11, 15 (Dec. 7, 2009).

[130] *Id.*

[131] Phase Two Direct Testimony of Thomas O. Anderson, p. 5 (Dec. 7, 2009).

[132] Supplemental Direct Testimony of Kimberly D. Flowers, pp. 2-3 (July 8, 2009).

enacted by the Congress—and/or regulations imposed by the Environmental Protection Agency—is likely and would result in explicit or implicit requirements to capture and sequester CO_2 from stationary sources, including power generation facilities.[133] The Company also testified that it believed it will be unable to obtain the funding and governmental approvals necessary to construct the Project without some level of carbon capture capability.[134] MPCo has studied several alternatives for various levels of CO_2 capture, and, based upon this analysis, the Company believes that it would be in the best interest of customers to design, build and operate the Plant with an approximate 65% capture level.[135] The carbon capture process being utilized for the Project is a commercial technology referred to as Selexol™. Mr. Anderson testified that the Selexol™ process is a commercial technology that uses proprietary solvents, but is based upon technology and design principles that have been in commercial use in the chemical industry for over 40 years.[136] Only Mr. Schlissel, in his direct testimony on behalf of Sierra Club, raised concerns about the Company's ability to capture the level of CO_2 contemplated by the Company, but his testimony offered no specific basis for his opinion that the Selexol™ process would be ineffective.[137] The Company witnesses testified in rebuttal that there are significant differences between "post-combustion" carbon capture processes and "pre-combustion" carbon capture process such as Selexol™ which has a forty-year track record of success in the chemical industry.[138] No other party contradicted the Company testimony on this issue.

---

[133] Order Finding Need for Generating Capacity and Energy, p. 13 (Nov. 9, 2009).

[134] Supplemental Direct Testimony of Kimberly D. Flowers, p. 3 (July 8, 2009).

[135] Phase Two Direct Testimony of Thomas O. Anderson, p. 21 (Dec. 7, 2009).

[136] *Id.* at 22.

[137] Direct Testimony of David A. Schlissel, pp. 18-19 (Dec. 7, 2009).

[138] *See* Rebuttal Testimony of Thomas O. Anderson, p. 13 (Jan. 5, 2010).

109. The Company plans to sell 100% of its captured CO_2 to one or more counterparties that operate enhanced oil recovery (EOR) projects in Mississippi, and the surrounding region.[139] According to the Company witnesses, EOR is a process by which a compressed gas (e.g. CO_2) is used to increase the productivity of depleted oil fields.[140] MPCo witnesses testified that the Company had been in discussions with multiple firms that have expressed an interest in purchasing the CO_2 produced at the Plant for use in EOR projects.[141] In fact, MPCo's Motion for Reconsideration contained an executed Letter of Intent from one of the two CO_2 Offtakers evidencing their intent to purchase the captured CO_2 on general terms consistent with MPCo's economic assumptions.[142] The Company also testified that it believes EOR activity and that industry's requirements for CO_2 will provide a vibrant market for the sale of the Project's captured CO_2.[143] Based upon this evidence, the Commission finds that the Company's design of the Project to capture 65% of the CO_2 output from the Plant and plan to sell the captured CO_2 to third parties is prudent and in the public interest.

110. The Company has requested that the Commission, as part of any certificate of public convenience and necessity issued in this proceeding, include in such grant the right for MPCo to own the CO_2 pipeline that would transport the CO_2 from the Plant site to the EOR projects. As proposed, MPCo would notify the Commission when it determines whether or not the option to own the CO_2 pipeline will be in the best interest of customers.[144]

---

[139] Phase Two Direct Testimony of Thomas O. Anderson, pp. 22-23 (Dec. 7, 2009).

[140] *Id.*

[141] *See* Direct Testimony of Kimberly D. Flowers, p. 47 (Jan. 16, 2009), and Phase Two Direct Testimony of Thomas O. Anderson, p. 23 (Dec. 7, 2009).

[142] Confidentially-filed Exhibit C to Mississippi Power Company's Motion for Reconsideration (May 10, 2010).

[143] Phase Two Direct Testimony of Thomas O. Anderson, (Dec. 7, 2009), p. 22.

[144] The Commission has since approved MPCo's ownership, construction and operation of the

111. The Project will also require extensions to and upgrades of MPCo's existing transmission lines and substation facilities. Mr. James D. Cochran, General Manager of Transmission Design and Construction, Southern Company Transmission, testified as to the various transmission facilities required as a result of the Project.[145] A detailed description of the facilities is included in Mr. Cochran's testimony and exhibits, as supplemented and revised in the Company's update provided in its Third Supplemental Filing on December 7, 2009, per the Commission's order. No parties offered any testimony contradicting the need for, descriptions of, or cost estimates developed for the transmission and substation facilities proposed by the Company in support of the Project. The Commission finds that there is substantial evidence in the record describing and supporting the need for the proposed 115 kV and 230 kV transmission and substation facilities and we adopt the descriptions of the transmission and substation projects as set forth in Mr. Cochran's testimony, including the general locations of said facilities, the right-of-way requirements necessary for the reliable and safe operation of those facilities, and the cost estimates for the facilities.

112. In its Third Supplemental Filing, the Company updated certain aspects of its Project economics and capital cost estimates. One of the items updated was the Company's decision to utilize the City of Meridian's treated municipal wastewater, also referred to as "gray water," for the Plant's cooling and process water requirements.[146] According to the Company witnesses, the addition of the pumping, pipeline and storage facilities will increase the capital costs of the Project, but those costs are more than offset over the life of the Project by the savings

---

approximately 60 miles of CO_2 pipeline by separate order issued in Docket No. 2011-UA-290. Docket No. 2011-UA-290 Order, p. 7 (Jan. 11, 2012)

[145] *See* Phase Two Direct Testimony of James D. Cochran, pp. 2-4 (Dec. 7, 2009).

[146] *See* Phase Two Direct Testimony of Thomas O. Anderson, p. 12 (Dec. 7, 2009).

of avoiding water treatment facilities and the operations and maintenance costs associated with treatment facilities.[147] The Plant will be a zero liquid discharge facility, meaning that no process water will be discharged into any rivers or streams.[148] We find that this feature significantly enhances the environmental benefits of the Project. The pipeline facilities for the City of Meridian gray water will be approximately 30 miles in length (total) and located in Lauderdale and Kemper Counties. The rights-of-way required for these water facilities are expected to be 50 feet in width, with 25 feet of additional width to be used during construction. The description and location of the water pipeline facilities are shown in Exhibit____(TOA-1), Appendix H, to Mr. Anderson's testimony. Therefore, the Commission adopts the descriptions of the pipeline project as set forth in Mr. Anderson's testimony, including the general locations of said facilities, and the right-of-way requirements necessary for the reliable and safe operation of those facilities, and the cost estimates for the facilities.

113. Ms. Flowers testified that the Project will require approximately five miles of natural gas transportation facilities and associated rights-of-way to accommodate natural gas deliveries to the Plant.[149] The gas lateral will commence at the proposed site and run east approximately five miles where it will tie into an existing gas transmission pipeline.[150] The gas lateral will be located in Kemper County, Mississippi. The rights-of-way required for these natural gas facilities are expected to be 50 feet in width, with 25 feet of additional width to be used during construction.[151] Therefore, the Commission adopts the descriptions of the pipeline

---

[147] *Id.* at 12-13.

[148] *Id.* at 13.

[149] Direct Testimony of Kimberly D. Flowers, p. 3, 37 (Jan. 16, 2009).

[150] *Id.* at 37.

[151] *Id.*

project as set forth in Ms. Flowers's testimony, including the general locations of said facilities, and the right-of-way requirements necessary for the reliable and safe operation of those facilities, and the cost estimates for the facilities.

114. The Company submitted extensive testimony on the various federal, state, and local incentives available to reduce the overall costs of constructing and operating the Project. To date, the Company has been granted approximately $270 million under the DOE's Clean Coal Power Initiative (CCPI).[152] The Company's Motion for Reconsideration later confirmed that the Company received notification that the final EIS had been approved for publication satisfying the last procedural requirement before the DOE issues its NEPA ROD committing DOE to provide the previously awarded CCPI funds.[153] In addition, the Company was allocated approximately $133 million in Internal Revenue Code Section 48A Investment Tax Credits (Phase I ITCs), and, as updated in its Motion for Reconsideration, additional Section 48A Investment Tax Credits (Phase II ITCs) totaling $279 million.[154] The Company is also seeking DOE loan guarantees.[155] As the Company discussed in its Supplemental Filing on July 8, 2009, and in its Third Supplemental Filing on December 7, 2009, the Project's lignite gasification equipment would be eligible for ad valorem tax exemption under certain conditions.

115. According to the testimony of various MPCo witnesses, the Company conducted a Front End Engineering Design (FEED) study to gather the pertinent cost and other data necessary for the evaluation of the Kemper County IGCC Project.[156] By way of example, the

---

[152] *See* Exhibit___(FT-11) to Phase Two Direct Testimony of Frances Turnage (Dec. 7, 2009).

[153] MPCo's Motion for Reconsideration, pp. 21-22 (May 10, 2010).

[154] *See* Phase Two Direct Testimony of Frances Turnage, pp. 7-8 (Dec. 7, 2009).

[155] *Id.* at 7.

[156] Phase Two Rebuttal Testimony of Thomas O. Anderson, p. 4 (Jan. 5, 2010).

FEED included conceptual design for the gasification island and other items such as the cooling towers and coal handling equipment, process flow diagrams, equipment specifications and foundation designs and layouts. The FEED study represents a comprehensive effort by the Company, utilizing expertise in numerous specialty areas such as chemical, mechanical, electrical, and civil engineering as well as construction layout and process design. The Company testified that the FEED study produced a thorough estimate of cost and performance for the Project.[157] As stated earlier, the quality of the estimate based on a FEED Study is higher than that normally presented at the certification stage.

116. The Company was the only party that produced detailed evidence as to the costs of the Project. The Company's cost estimates were presented in substantial detail in the testimony and exhibits of Ms. Flowers, as updated in the testimony and exhibits of Mr. Anderson in December 2009 per the Commission's order and as analyzed by Mr. Brazzell in his economic analysis. The cost estimate was developed through the FEED study, through various bid solicitations for major components of the Plant and through the experience of the Company and SCS. A breakdown of the estimated capital costs of the Project was presented in Exhibit____(TOA-1), Appendix B, filed confidentially, which is incorporated herein by reference. Other parties questioned the level of accuracy that can be expected from a FEED Study in general, [158] but no party presented any evidence to suggest the Company's FEED Study was flawed.

117. As explained in detail later in this order, the Commission finds that the Company's estimate was reasonably derived. Given the limited activities that a utility is

---

[157] Direct Testimony of Kimberly D. Flowers, p. 34 (Jan. 16, 2009).

[158] Phase Two Hearing Transcript, p. 1195.

authorized to do prior to receiving a certificate, it is generally unreasonable to expect the Company to produce, at this stage, a more detailed or accurate estimate. In fact, the Commission notes that the Company's FEED Study efforts exceed the level of detail that is typically undertaken in certificate proceedings. Nevertheless, the Commission must always be mindful of the uncertainties that may exist in an estimate and the possible consequences to customers that can arise. The Commission finds that the significant efforts to monitor the Project utilizing construction and engineering experts, and the cost cap established for the majority of the Kemper Project will sufficiently mitigate the risks associated with not having final estimates based on a detailed design.

D. Economic Evaluation Methodology and Natural Gas Forecasts

118. MPCo's evaluation compared the cost of all alternatives under consideration to determine the overall least-cost option for customers by calculating the net present value of incremental revenue requirements over the life of each alternative.[159] The revenue requirements include all fixed costs associated with the alternative, including recovery of construction capital, ongoing maintenance capital, fixed operation and maintenance (O&M), insurance, ad valorem tax, administrative and general, and fixed fuel.[160] These costs reflect any available incentives the alternative could receive.[161] The revenue requirements also include all variable costs including fuel, variable O&M, emission allowances/taxes, and system production cost savings.[162] These costs are also reduced by any incentives or benefits from salable product revenues that an

---

[159] Phase Two Direct Testimony of F. Sherrell Brazzell, p. 3 (Dec. 7, 2009).

[160] *Id.*

[161] *Id.*

[162] *Id.*

alternative may provide.[163] All alternatives were scaled to the same capacity rating so each alternative could be compared on a dollar per kW basis.[164] The revenue requirements calculated using this data were then discounted at MPCo's expected marginal after-tax weighted average cost of capital to calculate a cumulative net present value for each alternative.[165]

119. The same 16 scenarios used in the Company's Phase One needs analysis were also used for the Company's Phase Two economic evaluation of the self-build alternatives. Four fuel scenarios were constructed using a range of gas prices.[166] Four climate-change legislative scenarios were modeled for each of the four fuel scenarios.[167] This resulted in 16 individual, internally-consistent outlooks of correlated fuel prices and carbon compliance costs, electricity demand and prices, and capacity and energy mixes.[168] These 16 scenarios represent fully integrated results as opposed to the single-point estimates and sensitivities which have been used in past IRPs.[169]

120. The Company consistently testified that it was important to use a range of assumptions (represented by the collection of scenarios) when evaluating resource options, particularly long-term resources.[170] Boston Pacific's Dr. Roach agreed with the Company on this point:

---

163 *Id.*

164 *Id.* at 4.

165 *Id.*

166 Phase Two Direct Testimony of David F. Schmidt and Garey C. Rozier, pp. 4-5 (Dec. 7, 2009).

167 *Id.* at 5.

168 *Id.*

169 *Id.* at 4.

170 Phase Two Direct Testimony of Kimberly D. Flowers, p. 4 (Dec. 7, 2009); Phase Two Direct Testimony of David F. Schmidt and Garey C. Rozier, p. 4 (Dec. 7, 2009); Phase Two Direct Testimony of Christopher Ross, pp. 4-5 (Dec. 7, 2009).

> The use of scenarios is a good way to measure the risks. We would tend to pick the option that wins in a majority or more of the scenarios because it means that the option is the best deal for Mississippi ratepayers no matter how the future unfolds.[171]

While certain parties took issue with some of the assumptions used to generate the scenarios, no party presented evidence against using a scenario approach for evaluating the various options. For the above reasons, the Commission finds that the use of a range of scenarios to evaluate the relative economics of the alternatives is a reasonable and prudent approach.

121. All of the resource options (including the IPP bids) were evaluated across MPCo's 16 scenarios of gas price and carbon compliance forecasts. In addition, the Commission directed MPCo to conduct the evaluation of proposals on behalf of the Commission and directed the independent evaluator, Boston Pacific, Inc. to monitor and evaluate the evaluation process undertaken by MPCo. In addition, Boston Pacific, Inc. performed its own evaluation utilizing its own methodology. Finally, in the order, the Commission required that the evaluations include a sensitivity for fuel prices set 20% lower than those contained in MPCo's low natural gas forecast.[172] The Commission included a lower gas forecast for use in the range of scenarios as a proxy for significantly lower gas prices caused by an abundance of shale gas on the market, which was proffered as a plausible scenario by several parties. This addition resulted in a total of 20 scenarios of gas price and carbon compliance forecasts.

122. Considerable testimony was provided in both Phase One and Phase Two concerning the relative credibility of the various natural gas price forecasts presented by the parties for the Commission's consideration. MPCo's testimony explained that its four natural

---

[171] Report of the Independent Evaluator, p. 3 (Jan. 25, 2010).

[172] Mississippi Public Service Commission Order Granting Motions for Reconsideration, p. 2 (Dec. 15, 2009).

gas forecasts represented what it deemed to be a reasonable "range of future policy initiatives as well as a range of assumptions for other key variables that affect the demand for, and supply of, natural gas . . . ."[173] Three expert witnesses testified that MPCo's natural gas and CO_2 price forecasts represented a reasonable range from which to make long-term decisions.[174] The Sierra Club's expert Mr. Schlissel testified that MPCo's natural gas forecasts were too high when compared to recent Energy Information Agency (EIA) forecasts and recent trades posted to the NYMEX futures market.[175] Several parties also testified that the recent increase in shale gas production represented a fundamental shift in the natural gas markets such that low and stable natural gas prices could be expected well into the future.[176] Additional testimony regarding the various natural gas prices was heard during Panel B of the Phase Two Hearings.

123. While natural gas prices are relatively low today as compared to the recent past, evidence in the record demonstrates to the Commission that natural gas markets and prices are and will continue to be volatile.[177] The record contains several different forecasts of future natural gas prices that indicate a wide range of possible prices. MPCo demonstrated through several graphs and slides how volatile natural gas prices have been historically.[178]

124. After carefully reviewing the record, we find that the conflicting evidence on natural gas forecasts points out the difficulty in predicting long-term future natural gas prices. In

[173] Phase Two Rebuttal Testimony of Kimberly D. Flowers, David F. Schmidt and Garey C. Rozier, p. 6 (Jan. 5, 2010).

[174] *See generally* Phase Two Rebuttal Testimony of Christopher Ross (Jan. 5, 2010); Phase Two Rebuttal Testimony of Dr. Frank Clemente (Jan. 5, 2010); Phase Two Rebuttal Testimony of David Montgomery (Jan. 5, 2010).

[175] Direct Testimony of David A. Schlissel, p. 3 (Dec. 7, 2009).

[176] Rebuttal Testimony of Rebecca Turner, pp. 5, 11-13 (July 28, 2009); Direct Testimony of Robert Michaels and Samuel Van Vactor, pp. 5-6 (July 17, 2009).

[177] Phase One Hearing Transcript, pp. 112, 358; Phase Two Direct Testimony of Christopher Ross, pp. 4-6 (Dec. 7, 2009); and Phase Two Rebuttal Testimony of Frank Clemente, Ph.D., pp. 3-6 (Jan. 5, 2010).

[178] *See* MPCo's Late Filed Exhibits (Feb. 22, 2010).

order for the Commission to confidently pick one as more probable than the other, the Commission would be required to predict the outcome of several different variables, including but not limited to, the long-term availability of shale gas, the extent to which natural gas exports are permitted, the timing and severity of CO_2 compliance costs, the extent to which nuclear generation is expanded domestically, the extent to which natural gas demand increases due to the tightening of environmental regulations on coal generation, the extent to which traditional coal-fired generation is employed in the future, and the expanded use of natural gas as a transportation fuel.[179] For the reasons stated in the next section, the Commission does not adopt any one or a set of natural gas forecasts for the purpose of evaluating the relative economics of the alternatives under consideration. Instead, the entire range of scenarios was considered by the Commission.

E. Economic Evaluation of Kemper Project Versus IPP Bids

125. On December 7, 2009, MPCo submitted its updated cost estimate for the Kemper Proposal, and the results of its updated 2010 IRP and its self-build alternative economic evaluation. Also, on December 7, 2009, Entegra, KGen, and Calpine[180] submitted multiple purchase power proposals (PPAs) with terms ranging from 10 years to 25 years in duration and offering different fuel arrangements. All of the PPA bids received were from natural gas combined cycle facilities. In addition, some of the IPPs offered one or more of the generating assets in their portfolios to MPCo for purchase. The Sierra Club declined to propose a specific

[179] *See e.g.,* Second Supplemental Testimony of Kimberly D. Flowers, Frances V. Turnage and David F. Schmidt, pp. 14-15 (Aug. 28, 2009).

[180] Although a party to the proceeding, Magnolia did not submit a resource proposal for consideration in Phase Two.

alternative. Of all of the alternatives, the Kemper Project represents the only resource fueled by something other than natural gas, since no renewable proposals were received.

126. The Commission, in its order establishing the minimum bid requirements for resource proposals, indicated our preference for offers that included mechanisms for reducing the price volatility and escalation associated with natural gas fired generation. Any party wishing to provide price stability or to fix the price of natural gas during the duration of the contract period could do so in any manner it deemed necessary. In response to the Commission's request, two IPPs included offers to the Company that purported to provide fuel price protection for MPCo's customers for ten years commencing in 2014. The specific terms of all of the proposals are confidential and will not be restated in this order.

127. Each individual proposal, including the Kemper Project, was evaluated by the Company at the Commission's direction and by the Commission's independent evaluator, Boston Pacific, Inc., through Dr. Craig Roach and his staff. During the evaluation period, the Company and Boston Pacific shared information and collaborated to ensure consistency in input data and identify differences in methodology and results. At the conclusion of the evaluation period, on January 25, 2010, MPCo and Boston Pacific, Inc. each submitted separate and independent evaluation reports into the record prior to the Phase Two hearings. No party objected to the process established for the solicitation of resource alternative proposals, and no party objected to the use of Dr. Roach and Boston Pacific, Inc., as the independent evaluator of the bids or to the role of the Company in the bid evaluation process. The Commission finds that the market solicitation process utilized by the Commission in this proceeding afforded any interested party ample opportunity to participate in this proceeding and to submit a competitive offer for an asset sale or PPA. Moreover, the Commission finds that the use of the independent

evaluator to review the Company's evaluation methodology and to conduct its own independent evaluation created a robust and transparent process that served the public interest in this proceeding. The Commission's use of this solicitation and evaluation process was implemented in an attempt to ensure overall benefits to customers.

128. MPCo's economic evaluation used a methodology sometimes referred to as the Fill In Method to compare the IPP bids to both the Project and MPCo's natural gas combined cycle self-build alternative. The Company's Evaluation Report results indicated that the Project was more economic than the PPA offers in 15 of the 16 scenarios analyzed.[181] The asset purchase offers compared slightly better than the PPAs, but the Project was still more economic in 12 of the 16 scenarios analyzed.[182] The Company excluded the IPP fixed gas bids from its detailed evaluation because, after further inquiry, MPCo determined that the fixed gas bids were not credible.[183]

129. Boston Pacific's Bid Evaluation used two different evaluation methods to provide the Commission with what it referred to as long-term and short-term strategic preferences. Other strategic preferences presented in Boston Pacific's Evaluation Report include excluding the fixed gas bids, including only bids with terms of twenty years or more, including only asset purchase offers, and including only plants that are located in Mississippi.[184] Additional sensitivities evaluated the Kemper Project assuming that costs exceeded the estimate by 10% and 20%. Boston Pacific's Evaluation Report concluded that the "winner" depended upon the

---

[181] Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier, p. 11 (Jan. 25, 2010).

[182] *Id.* at 16-17.

[183] *Id.* at 17-20.

[184] Report of the Independent Evaluator, pp. 2-3 (Jan. 25, 2010).

Commission's strategic preference for long-term or short-term alternatives and its judgment of the credibility of the cost parameters of the various proposals.[185]

130. In this proceeding, it was necessary to compare the forty-year Kemper Project with IPP bids of lives varying from ten to twenty-five years. The Company's Fill-In Method used a self-build alternative at the expiration of each bid to "fill in" the remaining years of the evaluation period. According to the Company witnesses, this method ensured that each resource alternative is treated consistently over the entire forty-year evaluation period.[186] Boston Pacific's Extension Method assumed that the submitted bids continue to be selected by escalating the bid costs where appropriate to "extend" the term of the bid to fill in the remaining years of the evaluation period.[187] Both methods compared all of the bids over a forty-year period, and both produced results that concluded that Kemper is the best economic option for customers in the overwhelming majority of scenarios and across the many strategic preferences.[188]

131. At the hearings, a number of issues were raised by the Company witnesses concerning the Boston Pacific Extension Method. It was first claimed that a weakness of the Extension Method is that it assumes that the bid is available all forty years at the same terms and conditions as originally proposed.[189] The Company claims this assumption ignores the possibility that a bidder may often be willing to provide a lower bid in the short-term that the bidder may be unwilling to continue throughout the entire evaluation period, and, therefore, has

---

[185] *Id.* at 3-4.

[186] Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier, p. 9 (Jan. 25, 2010).

[187] Report of the Independent Evaluator, p. 27 (Jan. 25, 2010).

[188] *Compare* Exhibit____(MPC-Eval-5) to Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier (Jan. 25, 2010) *to* Tables E-8, E-9, E-10, E-11, E-12, E-13 & E-14 to Report of the Independent Evaluator (Jan. 25, 2010).

[189] Phase Two Hearing Transcript, pp. 1732-33, 1744, 1748.

the potential effect of unfairly favoring lower bids.[190] The Extension Method also ignores the possibility that lower cost options are available at the expiration of the bid.[191] Instead, the terms and cost of each bid are simply assumed to be extended for forty years.[192]

132. Boston Pacific also provided results from a second evaluation using the Modified Annuity Method. This method differs from the Fill In and Extension Method in that it does not require that all of the resources be evaluated over forty years.[193] According to Dr. Roach, this method "ignor[es] what happens after the shorter-term investment expires."[194] According to Dr. Roach, this method would be relevant in the event the Commission chose a strategic preference for shorter-term alternatives, but less relevant if the Commission was looking for a long-term resource.[195] The results of the Modified Annuity Method indicated that the Project was less economic than the "fixed gas" proposals in the majority of scenarios, but still remained competitive with the other PPA and asset purchase bids when the fixed gas proposals were excluded.[196] Therefore, Dr. Roach testified that if the Commission determined a strategic preference for a shorter term solution, such a decision would very much depend upon the Commission's judgment of the credibility of the fixed gas proposals.[197]

133. The Company also objected to the use of Boston Pacific's Modified Annuity Method in the evaluation. Boston Pacific justified the use of its Modified Annuity Method as a

---

[190] *Id.* at 1748-53.

[191] *Id.*

[192] *Id.*

[193] Report of the Independent Evaluator, p. 27 (Jan. 25, 2010).

[194] *Id.*

[195] *Id.* at 27-28.

[196] Appendix E to Report of the Independent Evaluator, Tables E-2 & E-9 (Jan. 25, 2010).

[197] Phase Two Hearing Transcript, pp. 1121-28.

tool to analyze the best short-term option available for those instances where the Commission wishes to "lock in the early-year savings and worry later about what comes next."[198] MPCo claimed the Modified Annuity Method is fundamentally flawed because it ignores and fails to address what happens after the shorter-term option expires.[199] MPCo's witnesses also claimed that the Modified Annuity Method only accounts for the first ten years of energy savings provided by Kemper and completely ignores the energy savings to customers provided throughout the remaining life of the Plant (i.e. 40 years or longer), which is a primary benefit of the plant.[200] The Company claims that such a short-term approach is not an accepted industry practice and could never justify the construction of a baseload facility, because long-term benefits that these facilities provide are heavily discounted or ignored in the analysis.[201]

134. MPCo also claimed that Boston Pacific's entire evaluation erroneously excluded a number of costs associated with the bids, thereby understating the true cost of the bids. These include the exclusion of certain transmission improvement costs necessary to deliver firm service to MPCo, certain equity costs necessary to maintain the Company's capital structure and credit quality if an IPP option was selected, and certain pre-construction costs that were prudently incurred to evaluate all options available to meet the need.[202] The Commission takes notice that many of these cost issues have been the subject of controversy across the country in similar proceedings for years, but have never been specifically addressed in Mississippi. While these costs appear appropriate to include in the economic evaluation of IPP bids, the Commission finds

[198] Report of the Independent Evaluator, p. 27 (Jan. 25, 2010).

[199] Phase Two Hearing Transcript, pp. 1724-25, p. 1854.

[200] *Id.* at 1725-27, 1729.

[201] *Id.* at 1591-92.

[202] *Id.* at 1772-75, 1782, 1785-87, 1916-18, 1920.

it unnecessary to resolve this conflict because the resolution is not integral to the Commission's decision. The Commission does take into consideration, however, that these omitted costs would serve to improve the relative economics of the Kemper Project, meaning that the results provided in the Boston Pacific Report represent a conservative approach to an economic comparison. This conservative approach provides more evidence that the Kemper Project is the most economic choice, and that the Commission's cost cap, which is discussed more thoroughly below, is supported by the appropriate and most credible evidence.

135. According to Dr. Roach, in order to properly interpret and weigh the credibility of the economic evaluation evidence contained in the record, the Commission must decide on certain "strategic preferences,"[203] namely (i) whether the Commission believes that a long-term or short-term solution is the overall best alternative for MPCo and its customers and (ii) the relative credibility of the fixed gas proposals and the Kemper cost and performance estimates. The Commission in its April and May Orders did not make specific findings concerning these issues, which we now believe is necessary to fully explain and support our conclusion to approve the Kemper Project.

136. Boston Pacific indicated in its report that the economic "winner" depended upon whether the Commission preferred long-term or short-term resource solutions:

> Who wins this competition – who wins the right to sell power to Mississippi ratepayers – is influenced importantly by what we have termed strategic preferences. The threshold strategic question is "What time horizon does the Commission want to consider?" The Commission has been offered primarily ten- and twenty-year resource options or solutions by the Bidders, but Kemper is offered as a forty-year option. There is no analytic or business reason to require all options to offer a forty-year solution. The proper time horizon is a matter for the Commission to decide.

[203] Phase Two Hearing Transcript, pp. 1122-23.

* * *

> [T]he answer to the question "Who Wins?" in the competition between Kemper and the Bidders depends on the Commission's strategic preference. The most important of these is the choice of time horizon.[204]

While recognizing the importance of the strategic preference identified, Dr. Roach was definitive in noting that the policy decision between a long-term or short-term solution is left to the sound discretion of this Commission.[205]

137. During the Phase Two Hearing, Dr. Roach described, in a very casual but accurate manner, some of the policy considerations facing this Commission regarding the time horizon preference.[206] For example, Dr. Roach indicated that if the Commission wanted to "lock in" savings in the first twenty years, as compared to Kemper, and be able to wait and see whether the future brought new technology or new information then a short-term solution would be best.[207] But, if the Commission wanted "a 40-year guarantee . . . a solution for 40 years, or . . . I just want a diversified fuel for 40 years,"[208] then a long-term solution favors Kemper.

138. Dr. Roach consistently characterized a short-term or natural gas option as a possible bridge to the future where new technologies might await to satisfy our capacity and energy needs.[209] Boston Pacific's report noted the Bidders offered only natural gas-fired combined cycle alternatives for ten or twenty years "consistent with the popularized view of natural gas as a 'bridge' to the future – that is, it will serve America's energy needs for ten or

---

[204] Report of the Independent Evaluator, pp. 3-4, 6 (Jan. 25, 2010).

[205] *Id.* at 4; Phase Two Hearing Transcript, pp. 1733-35.

[206] Phase Two Hearing Transcript, pp. 1733-36.

[207] *Id.* at 1734.

[208] *Id.* at 1735.

[209] *Id.* at 1556-57.

twenty years as new technologies are developed and perfected."[210] The IE, however, recognized that "[u]ncertainty over the future path for natural gas prices is the primary risk of choosing any of the Bids since they are all based on existing, natural gas-fired combined cycle power plants. Recent history shows us just how volatile natural gas prices can be and that volatility illustrates the uncertainty in any forecast."[211]

139. However, with approximately 53% of MPCo's generating capacity using natural gas as the primary fuel,[212] MPCo witnesses sharply disputed the notion that natural gas was a bridge to its future. The future, MPCo contended, is now; and the question is about baseload resources, not short-term options.[213]

140. Witnesses for MPCo offered compelling testimony that the prospect of change was a part of the utility world and always had been. Mr. Rozier pointedly noted that prior to Kemper the utility industry had made important decisions in the face of two Arab oil embargos, deregulation, open access to transmission, the advent of IPPs, a ban on the use of natural gas in electric utility boilers, numerous federal environmental laws, and the large-scale move away from coal-fired power.[214] As Mr. Rozier accurately stated:

> And I will tell you there's nothing unique about the fact that we're in a state of change and a lot of dynamics in the electric utility industry.
>
> * * *

---

[210] Report of the Independent Evaluator, p. 3 (Jan. 25, 2010).

[211] *Id.* at 22.

[212] *See* Direct Testimony of Kimberly D. Flowers, p. 17 and Appendix I to Exhibit ____ (KDF-1) (Jan. 16, 2009).

[213] Phase Two Hearing Transcript, pp. 1557-58, 1570-74, 1578-80, 1653-62.

[214] Phase Two Hearing Transcript, p. 1657

> There's nothing unique about change that is going on in the industry. The particular things that are going on might be different, but it's the world we live in.[215]

Dr. Montgomery drew the sharpest focus, framing the issue as follows:

> The issue I think we've all been talking about is whether in 10 years we will actually know more about the subsequent 40 years than you do today. I think that's the question you asked, and my answer to that would be I agree with the panel, the company witnesses.
>
> The uncertainty about what is going to be the best investment option over the next 40 years would be just as great 10 years from now as it is today, and that means, technically, that there's no value in waiting.[216]

141. Whether its oil embargos, nuclear catastrophes, environmental regulations, climate change, renewables or shale gas, the one certainty is that change, ingenuity, innovation and hope for a better future will always exist. Nevertheless, a public utility must prudently plan for its future, in part, to guard against uncertainty. The Kemper Project provides a long-term baseload generation solution that exists today and will provide a diversified and stable fuel source for the future, avoiding an overreliance on natural gas and its corresponding price volatility. The Commission finds that there is no benefit to waiting for ten more years to find a forty year solution that exists today.

142. Satisfying society's electricity needs reliably and economically always presents cost challenges. Undoubtedly, if natural gas prices persist at historic low levels for the long term then the Kemper Project will turn out more costly than a natural gas alternative. Also, Kemper has greater upfront capital costs, whereas the greatest cost (and the greatest risk) of a natural gas alternative lies in the fuel cost. After reviewing the range of possible fuel cost and carbon constrained scenarios, Kemper proves to be the dominant economic choice, even though the

---

[215] *Id.*

[216] *Id.* at 1662.

economics look different from a shorter-term, natural gas alternative. For example, Ms. Turnage explained the comparison between Kemper and a natural gas alternative, as follows:

> And it shows, for example, in our reference case, which is the moderate gas with a $10 CO2, over its life, Kemper would save customers $4.2 billion.
>
> And most of that, as I think you're pointing out, Mr. Young, is in the latter years of the life of facility. That's why you invest in baseload generation is to get those savings on the back end.[217]

143. Long-term planning, particularly with baseload generation, spreads costs and benefits out over time. As Mr. Rozier observed:

> This is Mississippi Power's current fleet, and you see there the Greene County Units are 48, 49 years old, Watson, 41 to 46 years old, Daniel, 33 to 37 years old. Other units even longer age.
>
> I think we can agree that we have to look to the long-term. We have to look over a wide range of scenarios, and that the payback for the capital we invest is not totally certain, and the fuel costs we're going to experience is not completely certain.
>
> There are those issues that we have to deal with, but by and large, you invest in the long-term assets to produce long-term stable rates, and a short sided approach will not serve Mississippi's customers well.
>
> And you know, we have a good range of fuel prices that have been looked at in the 16 scenarios the company looked at. The Commission indicated maybe they wanted to look at a lower set of gas prices, which as our witnesses have told you are not sustainable over the long-term.
>
> Long-term assets have to be put in place to get long-term benefits financed by long-term financial commitments, and that's to the benefit of Mississippi Power's customers.[218]

144. Costs and benefits of long-term, baseload assets are also spread out and equalized between generations of ratepayers. Again, as accurately explained by Mr. Rozier:

---

[217] *Id.*at 1573.

[218] *Id.* at 1570-71.

> While -- when the Kemper facility comes in, it is at the beginning of its life. It is producing benefits in every year. It's stabilizing energy -- our energy costs. Customers are benefiting from that.
>
> Over time, that capital we invested will pay itself off in terms of a long-term investment decision, but at the same time customers are paying those rates that include Kemper, they're paying the highly depreciated rates for those units that were built 20 and 30 years ago, and it all bundles together.
>
> We're not going to be going to any customers and asking them to pay Kemper rates. They're going to be paying the rate for the total fleet which includes investing in that fleet over the long haul, and that's the only way you can look at a baseload decision is over the long haul, because we're benefiting from those baseload decisions in the current rates.[219]

145. Focusing on short-term solutions, and particularly the cost of a shorter term option in comparison to a longer-term solution, can lead to bad decision making. Dr. Montgomery best illustrates this point in the following testimony:

> We've now gotten to Mr. Schlissel is now applying that calculation in a way that leads directly to the conclusion that no one would ever build a baseload power plant, and I'm afraid that is exactly the direct -- and that is the implication that I take from Mr. Young's questions.
>
> If we look only at the first 10 years of a baseload power plant, we would -- that has a high capital cost, whether it is coal or hydro or nuclear or renewables, we would conclude that, over that time period, you would be much better off buying a PPA that has a small capital charge.
>
> The problem is that when you got to the end of that 10-year period, you would conclude exactly the same thing, and the next 10-year period you would conclude exactly the same thing.
>
> So over 40 years, if you made your decisions in this sequential shortsighted way, you would consistently choose something that at the end of those 40 years you would look back and say that was a really stupid decision, because if I had just looked forward enough, I would have realized it was worth paying the cost of that baseload power plant, and that's the fallacy of trying to look for these years in which there is a break even.

---

[219] *Id.* at 1578-79.

> You can't say that it's a good idea to be shortsighted, look out only 10 years, and in fact -- in fact, I think that there is a very important -- since you're looking at revenue requirements, it's very important to remember the point that . . . Mr. Rozier said that in a regulated environment, the ratepayer gets the benefit of having depreciated out the cost of an old power plant.
>
> Now, if MPCo had, throughout its entire history, been buying power from independent power producers on PPAs, those power producers would have always been earning a profit.
>
> In fact, those 60-year old power plants would right now hold the MPCo consumers is paying is the fuel and operating cost would have beenearning a profit for their IPP owners.
>
> So if at that point MPCo went out and built a baseload power plant, there would be a big rate shock, because you would be adding a capital charge on top.
>
> What's happening now as described is simply a sequence of investments which are made and then depreciated out, made and depreciated out, and as we do that over time, you come out much more cheaply than you would have been buying power at a much higher price over that period.[220]

This Commission favors a long-term solution over a short-term option.

146. Building and crossing a natural gas bridge to the future would require this Commission to embrace the historic volatility of natural gas prices and to potentially compound that decision by forcing MPCo to rely almost exclusively on natural gas. As testified by one of its witnesses, a natural gas option would move the Company's energy portfolio to 70% reliance on natural gas.[221] The Commission finds significant potential harm in such overreliance and does not favor this approach.

147. Dr. Roach agreed, as exhibited by this exchange with Commissioner Bentz during the Phase Two Hearing:

[220] *Id.* at 1591-93

[221] Phase Two Hearing Transcript, p. 1602.

> COMMISSIONER BENTZ: Dr. Roach, I'm hearing a lot about this gas and 10 years. The question I need to ask, do you feel the utility company is being prudent to the ratepayers if they're 70 percent dependent on natural gas?
>
> DR. ROACH: That's -- you know, I haven't really addressed that. I think that is a worry. There's no doubt about it. Fuel diversity matters. I think I've been presuming, although it's not my place to presume, that you would not go forward, necessarily, with the gas option if it didn't offer you some fixed gas prices so you wouldn't face that risk, you wouldn't have that risk. So that's my presumption, but you'll make your decision.[222]

Additionally, Boston Pacific noted that without producing innovative fixed-price natural gas supply deals the natural gas industry would not be able "to secure a place for base load gas-fired electricity generation."[223]

148. The Commission finds that fuel diversity matters, particularly because fuel price stability matters. The Kemper Project offers both, giving MPCo a third fuel source for its generation fleet and utilizing a lignite resource owned by the Company and mined at the mouth of the Kemper plant. Lignite will be subject to neither transportation costs nor market pressure, thereby offering near price certainty and transparency.[224]

149. Having reviewed the evidence concerning the different methodologies, the Commission finds that a long-term baseload solution is in the best interest of customers. Because MPCo and the Commission have obligations under the Act to ensure that customers are being served safely, reliably in a cost-effective manner, it is not prudent to consider evaluations that fail to consider what happens after the short-term option expires or is no longer available.[225] The regulated utility industry is characterized by large, long-lived capital investments, which

---

[222] *Id.* at 1604-05.

[223] Report of the Independent Evaluator, p. 24 (Jan. 25, 2010).

[224] *See, e.g.*, Phase Two Hearing Transcript, pp. 1803-04.

[225] Phase Two Hearing Transcript, pp. 1724-25, 1854.

does not easily allow for a utility to ignore long-term planning needs or the consequences of making a short-term decision. Based upon these findings, the Commission determines that a long-term resource alternative is the overall best option for MPCo and its customers at this time.

150. Although the Commission's finding in favor of a long-term baseload solution leaves little need to pass upon the fixed-price natural gas bids, the Commission will, nevertheless, consider the matter.

151. Considerable testimony and evidence was presented both in favor of and against the inclusion of the fixed gas bids in the economic analyses. As a result of this testimony, we are concerned that none of the parties in the proceedings were themselves able or willing to provide a fixed natural gas price to MPCo's customers for even ten years. Certinaly, no "strong letter of intent" or actual contract was forthcoming.[226] The IPPs claimed that such an arrangement could be accomplished through a financial institution although all of the parties agreed that a ten-year fixed gas contract had not been done in the past and was entering "new territory."[227] MPCo testified that despite its best efforts to date, a fixed gas contract for the term proposed was impossible to execute, because there were no willing counterparties and the credit risks were too high.[228] MPCo also testified that the potential cost, if available, to secure even a ten-year fixed gas deal could be over $1 billion for only ten years of limited fuel price protection within some narrow range around the price of the gas commodity.[229] After reviewing the proposals and the

---

[226] *Id.* at 1608-08.

[227] *Id.* at 1800, 1839-40.

[228] *Id.* at 1832-34, 1955, 2019-20. Margining Risk would arise when MPCo's mark to market exposure for the financial hedge transaction exceeds the credit thresholds and the Company has to post collateral. Phase Two Supplemental Testimony of Frances Turnage, p. 7 (Jan. 25, 2010). Counterparty risk is the risk that MPCo's counterparty is unable or unwilling to perform under the hedging contract, exposing MPCo to the natural gas price risk that it thought it had hedged to avoid.

[229] Phase Two Supplemental Testimony of Frances Turnage, p. 7 (Jan. 25, 2010).

testimony contained in the record, the Commission finds that the fixed gas proposals offered by the IPPs are not credible. The fixed gas proposals only amount to a suggestion that MPCo seek additional hedging contracts with financial institutions that have not provided offers and were not parties to this proceeding.[230]

152. 10-year fixed gas price contracts, economical or otherwise, appear to be fiction at this point, as illustrated by Commissioner Bentz at the Phase Two Hearings:

> COMMISSIONER BENTZ: Mr. Sweeney, have you ever done a fixed price 10-year deal?
>
> MR. SWEENEY: Never done a fixed price 10-year deal, but yes, I have done 10-year buys.
>
> COMMISSIONER BENTZ: Entegra, have they ever done a 10-year fixed deal?
>
> MR. BRONNER: We've done 10-year tolling arrangements, but we -- I have not done 10-year gas arrangements.
>
> COMMISSIONER BENTZ: Mr. Hempling, why are we stuck on this 10 years?
>
> MR. HEMPLING: Well, I don't know the answer to that, sir.
>
> COMMISSIONER BENTZ: Why aren't we talking 20 and 30 years?
>
> MR. HEMPLING: Sir?
>
> COMMISSIONER BENTZ: Why are we talking 10 years, I'm wanting you to give me some advice. Are we not trying to fix the problem for 20, 30, 40 years down the road?[231]

The Commission finds that the fixed gas proposals are not credible and excludes them from consideration.

---

[230] Phase Two Hearing Transcript, pp. 1613-14, 1816-19, 1824-34.

[231] *Id.* at 1838.

153. When the fixed gas proposals are removed from consideration and a strategic preference for long-term resources is made, the economic evidence becomes much clearer and more convincing to the Commission. MPCo's Fill In Method and Boston Pacific's Extension Method produced comparable results,[232] and both indicated that the Kemper Project was the clear economic winner in the overwhelming majority of scenarios, which examined all relevant IPP bids and the self-build natural gas option.[233] In both of these methods combined, the Kemper Project wins in 47 of the 56 scenarios considered if the fixed gas proposals are eliminated.[234] Even the Modified Annuity Method results (a short-term evaluation method) indicate that the Kemper Project is more than economic when the fixed gas bids are removed from consideration.[235] Dr. Roach's testimony agrees with these findings—namely, that if Kemper's costs are considered more credible than the fixed gas bids[236] and/or if the Commission has a strategic preference for longer-term options,[237] then the Kemper Project is the economic "winner." Therefore, the Commission finds that the overwhelming weight of the credible evidence in the record concerning the economic performance of the various alternatives, including a self-build natural gas option, indicates that the Kemper Project is the economic option in a significant majority of the scenarios and under the many strategic preferences presented.

---

[232] Report of the Independent Evaluator, p. 35 (Jan. 25, 2010).

[233] *Compare* Exhibit___(MPC-Eval-5) to Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier, pp. 12, 17 (Jan. 25, 2010) *to* Tables E-8, E-9, E-10, E-11, E-12, E-13 & E-14 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[234] *See* Figures 2 & 4 in Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier (Jan. 25, 2010); Table E-9 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[235] *See* Tables E-2 & E-4 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[236] Phase Two Hearing Transcript, p. 1126.

[237] Phase Two Hearing Transcript, pp. 1128, 1851-52.

154. The Commission is not required to adopt any gas forecast (to the exclusion of others) to support its finding that the Kemper Project is in the overall best interest of MPCo's customers. Instead, the Commission has considered the effect of the various natural gas prices on the economic analysis of the Kemper Project under all of the credible scenarios presented. We find only that the range of gas price forecasts were supported by evidence in the record and are reasonable. Moreover, the range of possible outcomes based upon the various natural gas price forecasts demonstrates that the Kemper Project is the economic choice in several different possible futures, making the Kemper Project the most robust decision from a risk mitigation prospective. In other words, the Commission finds that the fuel diversity and price stability offered by the Kemper Project's baseload capacity and energy provides substantial benefits to MPCo's customers beyond the obvious economic benefits presented in a number of the scenarios evaluated, a finding to which we assign significant weight.

F. POTENTIAL RISKS OF KEMPER PROJECT

154. Throughout this proceeding, MPCo has described the significant strategic and economic benefits associated with the Kemper County IGCC Project. However, the proposed Project represents one of the largest electric generation projects ever proposed in the State of Mississippi, and if built, would become one of the first IGCC plants in commercial operation with carbon capture in the world for the generation of electricity. Several parties have pointed out and the Commission has been concerned about the potential risks to the Company and customers posed by the Project, including capital cost risk, performance risk, first of a kind technology risk, project cancellation risk, and the potential loss of federal incentives.

155. Testimony provided shows that MPCo's cost estimates for the Project are subject to multiple uncertainties. MPCo's witness stated that as of the hearing, only ten percent (10%) of

the estimated construction cost was confirmed."[238] MPCo's Motion for Reconsideration later updated this figure to approximately twenty percent (20%) of the total construction cost estimate.[239] A cost is confirmed if there is a contract, memorandum of understanding or a letter of intent; or if MPCo has received bids in response to a request for proposals.[240] Therefore, the record before the Commission shows eighty percent (80%) of the current construction cost estimates are internal MPCo estimates that have not been "confirmed."

156. The fact that most of the Project costs were estimates is not, in itself, fundamentally a concern. All facility certificates are issued based upon estimates, especially electric generation and transmission facilities. As explained below, MPCo has demonstrated that its estimating process is reasonable and sound and that the Company has the requisite expertise to prepare facility cost estimates. However, every estimate contains elements of uncertainty, and depending upon the magnitude, these uncertainties can represent a significant risk to customers.

157. As the Commission has stated in this Order, the certificate process provided under the Act requires that a utility request approval prior to final design, obtaining all permits, executing all construction and procurement contracts, etc., which necessarily creates a level of uncertainty in the cost estimate that is unavoidable. However, we feel it is helpful to briefly summarize the record evidence concerning several of these uncertainties associated with MPCo's Kemper Project cost estimates:

<u>Plant Design</u>. The Company has not yet completed detailed design. Concerning the gasification island, MPCo's witness stated ". . . we do not have hardly any of the detailed

[238] Phase Two Hearing Transcript, p. 1138.

[239] MPCo's Motion for Reconsideration, p. 26 (May 10, 2010).

[240] Phase Two Hearing Transcript, p. 1137.

design done."[241] The fact that detailed design was not complete on much of the plant creates cost uncertainties in the Company's estimates, although the lack of detailed designs is not unique to the Kemper Project application.

Ash Storage. MPCo bases its cost estimate on a sixty-five (65) acre storage unit, which would store the ash. The cost estimate applies to the first five (5) years of Kemper operation only. An alternative storage concept posed by MPCo is the development of 500 acres, an activity which is not covered by its cost estimate. Mr. Anderson testified that the cost of the additional acreage could range from $20 to $100 million, a range made necessary by the uncertainty concerning EPA regulations affecting ash storage.[242] Additionally, MPCo's Motion for Reconsideration indicated that the EPA's Pre-Publication Version of its Proposed Rule for Coal Combustion Residuals, confirmed that this rule is not likely to apply to the Kemper Project, removing this cost estimate uncertainty.[243]

Right-of-Way. Our April Order mistakenly stated that there were no arrangements in place to acquire rights-of-way for three (3) pipelines critical to Kemper's operation. MPCo's Motion for Reconsideration clarified the evidence in the record that the Company had entered into several option contracts that provide a contractual right to purchase much of the needed right-of-way upon issuance of a certificate.[244] Nevertheless, a significant portion of the rights-of-way for the Project remained unacquired and not subject to option as of the date of the Company's Motion, creating uncertainty in the Company's overall cost estimate to complete. The Commission takes notice, however, that MPCo is authorized to exercise the

[241] Phase Two Hearing Transcript, pp. 1268-70.

[242] *Id.* at 1260-66; *see also* MPCo's Response to Entegra 1-23 (April 8, 2009).

[243] MPCo's Motion for Reconsideration, p. 16 (May 10, 2010).

[244] *Id.*; As of the date of the Motion for Reconsideration, MPCo had optioned 34% of the transmission, 21% of the gray water pipeline and 48% of the natural gas pipeline rights-of-way. *Id.*

power of eminent domain, which reduces the risk that any necessary rights-of-way cannot be acquired at market value.

Lignite Leases. As of the date of the Phase Two Hearings, MPCo had acquired lignite leases for only about half of the necessary supply, reflecting about 5,000 acres.[245] In addition, MPCo's original proposal in 2009 assumed it would purchase lignite for forty (40) years at a fixed price. MPCo now expects to own the mine, paying a contractor to mine the lignite for a fee, but this arrangement is not exactly the same as a fixed-price contract. MPCo provided a confidential estimate of the capital cost of owning the mine.[246] Because only a portion of the necessary mineral leases have been acquired, MPCo's lignite price projections contain some level of uncertainty. The uncertainty of this category of cost is increased by the fact that neither MPCo nor its parent has ever owned a lignite mine.[247]

Transmission. To transmit Kemper's output to the MPCo's electric grid reliably, MPCo asserts it needs to construct sixty (60) miles of transmission system upgrades and three (3) new substations. It has not acquired the rights-of-way for these facilities; nor has it completed detailed design work.[248] These factors render its cost estimates uncertain. The Commission takes notice, however, that MPCo is authorized to exercise the power of eminent domain, which reduces the risk that any necessary rights-of-way cannot be acquired at market value.

By-Product Revenues. Kemper's operation would produce by-products: CO_2, ammonia and sulfuric acid. MPCo hopes to sell these by-products, with the revenues offsetting Kemper's cost to ratepayers. MPCo offered estimates of these revenues, but those estimates

[245] Phase Two Hearing Transcript, p. 1247-49.

[246] *Id.* at 1352.

[247] *Id.* at 1299.

[248] *Id.* at 1273-74.

were not supported by any contracts.[249] MPCo's witnesses at hearing described a large national market for these products, but their assertions did not sufficiently take into account transportation associated with selling the ammonia and sulfuric acid to that large geographic area; nor did they reflect any study of the number and viability of competing sellers of the by-products.[250] Based upon these facts, the revenue stream from by-product sales contained in the Company's economics is uncertain.

Liquidated Damages Clauses. The April Order indicated that the record was absent of any specific evidence on the value or likelihood of liquidated damage provisions, which we found created uncertainty as to the ratepayer risk for under performance or vendor default. However, the Company's Motion for Reconsideration cited substantial evidence already contained in the record concerning the Company's efforts during the procurement process to negotiate reasonable warranty and liquidated damages provisions where commercially available.[251] However, no warranty or liquidated damages clause was negotiated for the TRIG™ gasification technology. Therefore, the Commission finds that the Company is taking reasonable efforts to obtain contractual protections when available, but uncertainty still remains with respect to the TRIG™ technology.

Environmental Permits. Kemper's construction requires environmental studies, permits and other approvals. As of the date of the April Order, MPCo did not have a final Environmental Impact Statement ("EIS") under the federal National Enviornmental Policy Act ("NEPA"), nor did it have an air permit revision requested from the Mississippi Department of

[249] MPCo's Motion for Reconsideration did, however, include a copy of a recently executed Letter of Intent from one of the CO_2 offtakers expressing an intent to purchase the captured CO_2. Confidentially-filed Exhibit C to MPCo's Motion for Reconsideration (May 10, 2010).

[250] Phase Two Hearing Transcript, pp. 1346-48.

[251] MPCo's Motion for Reconsideration, pp. 19-20 (May 10, 2010).

Environmental Quality ("MDEQ"), to reflect the turbine characteristics.[252] The Commission's initial concern was that delays in project completion due to delays in permit acquisition would add to Kemper's cost. However, MPCo's Motion for Reconsideration provided significant updates for both the EIS NEPA Record of Decision ("ROD") and the MDEQ's revised PSD Air Permit that largely resolves the Commission's concern with these uncertainties.[253]

<u>Government Incentives</u>. MPCo's estimates, and its assertions of Kemper's cost-effectiveness, assume a variety of government-funded benefits, including grants, tax incentives and loan guarantees. The values include a $296 million reduction in upfront capital costs and a reduction of over $1 billion in operating costs.[254] These benefits vary in their certainty—MPCo has secured DOE approvals for the CCPI funds (DOE funding is contingent upon NEPA ROD) and Section 48A Phase I ITCs, but as of the Phase Two Hearings the Company had not yet been allocated the Section 48A Phase II ITCs and the loan guarantee.[255] While the allocation of the $279 million in Phase II tax credits helps,[256] until fully realized and collected, the government incentives are another source of uncertainty for ratepayers.

158. Between April 2009 and December 2009, MPCo increased its estimate of Kemper construction cost by over nine percent (9%), from $2.465 billion to $2.695 billion (these numbers would be reduced by the government-provided incentives). In pre-filed testimony and at hearing, MPCo's witness described the reason for each element of this increase.[257] The

---

[252] Phase Two Hearing Transcript, pp. 1298-99.

[253] MPCo's Motion for Reconsideration, pp. 20-22 (May 10, 2010).

[254] Exhibit___(TOA-1) to Phase Two Direct Testimony of Thomas O. Anderson (Dec. 7, 2009); Exhibit___(FT-11) to Phase Two Direct Testimony of Frances Turnage (Dec. 7, 2009).

[255] *See* Phase Two Direct Testimony of Frances Turnage, p. 8 (Dec. 7, 2009).

[256] MPCo's Motion for Reconsideration, p. 22 (May 10, 2010).

[257] *See* Phase Two Direct Testimony of Thomas O. Anderson, pp. 15-16 (Dec. 7, 2009).

reasons included changes in plant design, as well as increases in cost estimates for equipment, labor, and materials. There was also an increase in the contingency. MPCo testified that much of the cost increase was a result of scope and design changes that provided net benefits in the form of lower overall cost to customers over the life of the Project. This argument does not change the Commission's concern; the question is not whether the cost increases are justified but whether the Commission can rely on MPCo's cost estimates given the preliminary nature of the FEED Study as evidence of the final Kemper Project costs that will ultimately be asked to be borne by customers.

159. In a long-term construction project, it is not unusual for various cost items to be uncertain at the time a utility files a petition for a certificate. As we have stated, the Act does not require or even contemplate every cost component to have detailed evidentiary support, and every permit to be in place. But in this case, the cumulative effect of the possibility of construction cost increases and delays, the cost of any delays, and feasibility questions relating not only to the technology, but also to the acquisition of basic ingredients like leases, land and permits, combine to create too much uncertainty for the full risk to be borne solely by ratepayers. Although the Commission believes that the significant benefits of Kemper (described below) support an overall decision to approve the Project, based upon all of this evidence, the Commission finds there is a risk of cost increases. To appropriately balance these risks between the Company and customers, certain conditions have been created that are discussed later in this Order. These conditions have the effect of allocating an appropriate level of risk to MPCo, consistent with the economic evaluations produced in the record and consistent with the public interest.

G. APPROVAL OF THE KEMPER PROJECT

160. After carefully evaluating both the benefits and risks to customers of the Kemper Project and recognizing the Legislative policy determinations applicable to new baseload technologies, the Commission finds that the evidence presented by MPCo in this matter was sufficient to meet the Company's burden of proof to support a need for the construction, acquisition, and operation of the Kemper County IGCC Project. For the following reasons, the Commission finds that the Kemper County IGCC Project is the best overall alternative available to serve the Company's growing customer demand over the long term and to meet other strategic objectives important to the Commission, the Company and customers:

First, the Commission finds that the Project will enhance the fuel diversity and asset mix of MPCo's generating fleet, thereby mitigating the supply and price volatility risks associated with the predominant use of any one fuel. The Commission believes that fuel diversity is critical to keeping MPCo's prices to customers low and stable over the long-term. Today, MPCo's generating fleet is limited to two fuels, traditional coal and natural gas. If Plant Watson Units 4 and 5 remained uncontrolled, over 70% of MPCo's existing fleet will be burning natural gas. Such dependence on one fuel source is not prudent for the Company or its customers. Specifically, the TRIG™ IGCC technology will allow MPCo to use a third fuel source—lignite, a lower-rank (i.e. lower heating value) fuel whose cost is both lower and less volatile than the cost of natural gas and higher-ranked coals.[258] The record has extensive evidence on natural gas prices since they were deregulated in the 1970's, and two things are not rebuttable: During that time natural gas prices have been extremely volatile, and their trend in pricing has been upward for the last 50 years. Kemper will provide MPCo and its customers a long-term, low stable-priced fuel in locally mined lignite. The fuel diversity and price stability

[258] Direct Testimony of Kimberly D. Flowers, pp. 6-7 (Jan. 16, 2009).

offered by Kemper to the customers of MPCo is a significant factor supporting the Commission's decision. The Commission finds that maintaining long-term fuel diversity is critical to keeping MPCo's prices to customers low and stable over the next several decades.

Second, because of the immense lignite reserves located in the State of Mississippi, particularly the Damascus Reserve, the Plant can be located adjacent to nearby lignite reserves in a mine-mouth arrangement that will effectively eliminate fuel transportation costs and insulate the Company from fuel supply and transportation market fluctuations.[259] The Commission finds that the lignite mining agreement with Liberty Fuels, LLC will provide a lower and more stable fuel price over the life of the Plant, which is estimated to be at least 40 years. Because of these factors, we find that over the life of the Project the energy benefits provided by the Project far out-weigh the higher initial capital costs to construct.

Third, we find that the Project provides the Company and the Commission with far greater flexibility to address significant environmental compliance decisions that will face the Company in the 2013-2015 time frame for Plant Watson Units 4 and 5. As we determined in our Phase One Order, the Company's plans to retire Plant Eaton Units 1-3 and Plant Watson Units 1-3 are reasonable.[260] The Company sought and was granted authority in Docket No. 2010-UA-279 to construct and install flue gas desulfurization equipment at Plant Daniel Units 1 and 2 for commercial operation by the end of 2015.[261] Due to its baseload characteristics, the Kemper County IGCC Project provides MPCo with additional baseload capacity and energy that will allow the Company to defer a decision on the appropriate strategy to employ for Plant Watson

---

[259] *Id.* at 7.

[260] Order Finding Need for Generating Capacity and Energy, p. 11 (Nov. 9, 2009).

[261] MPSC Docket No. 2010-UA-279, Final Certificate Order (April 3, 2012).

Units 4 and 5.[262] By deferring a decision to control Plant Watson Units 4 and 5, the Company and Commission can better assess and delay the ultimate impacts and compliance options and costs to customers for meeting any future limitations on carbon emissions, potentially avoiding all together hundreds of millions of dollars in additional capital expenditures.[263]

Fourth, we find that the Plant will include state-of-the-art equipment to reduce various emissions from the Plant, including equipment for the capture of approximately 65% of the Plant's CO_2 emissions, all of which will ensure compliance with existing environmental laws and regulations and mitigate the future risk associated with the passage of climate change legislation which the Commission finds to be probable.

Fifth, we find that support for clean coal technologies, such as that proposed for the Kemper County IGCC Project, has been very strong at the federal, state and local levels. As a result, there are significant financial incentives available that help lower the overall cost of the Project to the Company and its customers. These financial incentives include Section 48A Phase I and Phase II ITCs, DOE loan guarantees, external funding from the DOE's CCPI, and various other state and local support. Cumulatively, these benefits exceed $332 million (Total Company) in construction cost reductions and $1,372 million (Total Company) in operations and maintenance (O&M) expense reductions over the life of the Project.[264] Considerable resources and effort from all levels of government have been allocated and expended specifically to support the Project. The Commission finds that the Company should exercise all reasonable diligence to apply for and obtain all of the federal, state, and local financial benefits it has identified and any others for which the Project qualifies.

---

[262] Phase Two Direct Testimony of Kimberly D. Flowers, pp. 11-12 (Dec. 7, 2009).

[263] *Id.*

[264] *See* Revised Exhibit____(FT-11) to the Phase Two Direct Testimony of Frances Turnage.

Sixth, we find that the Project is expected to have a considerable economic development impact at both the state and local levels. According to the un-refuted Company testimony, approximately 1,000 jobs will be created at the peak of the construction phase (500 jobs on average) and approximately 260 to 280 permanent, quality jobs will be created in both the power and mine facilities.[265] The Project will also result in increased state and local tax revenues, the infusion of mineral royalties into the Kemper County area and the opportunity for increased commercial and industrial development both related and unrelated to the operation of the Project.[266]

Seventh, we find that because the Plant will be fueled by Mississippi lignite, the Project will demonstrate the value of lignite and provide the catalyst to expand lignite business opportunities in the State. The Company estimates that Mississippi has approximately four billion tons of recoverable lignite reserves, representing significant untapped potential for economic development in Mississippi and the region.[267] We find that the Project presents a unique opportunity to position lignite as another potential fuel source in a carbon-constrained environment by utilizing a relatively untapped Mississippi natural resource.

Eighth, we find that the Project has the opportunity to provide considerable strategic and economic development value to the State and the nation. Utilizing Mississippi lignite in a cost-effective, environmentally responsible manner furthers both the State's and the nation's stated goal of increased energy independence, as well as the federal agenda of developing clean coal technologies and utilizing EOR as an effective solution for carbon sequestration and reduction of greenhouse gases. In fact, the DOE submitted three separate

[265] Direct Testimony of Kimberly D. Flowers, p. 8 (Jan. 16, 2009).

[266] *Id.*

[267] *Id.*

filings in this proceeding specifically supporting the Project and indicating its important role in developing clean coal technology for the nation.[268]

Ninth, we find that the carbon capture capabilities of the Plant, beyond their potential environmental benefits, will foster the development of EOR projects in the State. These EOR projects are expected to translate into an increase of domestic oil production of several million barrels a year.[269]

Tenth, as detailed above, we find that the results of the IRP performed by the Company and the economic evaluations conducted in this proceeding clearly indicate that the Kemper Project is the most economic resource alternative available to meet MPCo's identified need in the majority of the credible scenarios analyzed. The Commission determined that there was a need for additional capacity in its Phase One Order. The Commission finds that the Company conducted a detailed screening and evaluation, including a robust economic analysis, which indicates overwhelmingly that the proposed Kemper County IGCC Project is the best generation resource alternative to meet MPCo's identified need. The Project was selected from a variety of alternatives, including nuclear, pulverized coal, combined cycle natural gas fired, and combustion turbine natural gas fired.

Eleventh, as previously found in this order, the Kemper Project is the clear economic choice when compared to the natural gas IPP bids, including the natural gas self-build option, offered in Phase Two. The Commission's strategic preference for a long-term resource and the Commission's finding that the Kemper Project is more credible than the fixed gas bids,

---

[268] Letter from Steven Chu, US Energy Secretary to Mississippi Public Service Commission (May 19, 2010) (on file in MPSC Docket No. 2009-UA-14); Phase Two Direct Testimony of James J. Markowsky (Jan. 29, 2010); Informational Filing on Behalf of United States of America, Department of Energy (Oct. 1, 2009).

[269] Direct Testimony of Kimberly D. Flowers, p. 9 (Jan. 16, 2009).

confirm that the Kemper Project is the most economical alternative in the overwhelming majority of scenarios.

161. All of these findings combined, which are supported by substantial evidence in the record, clearly support a finding that the public convenience and necessity requires or will require the construction, acquisition, operation, and maintenance of the Kemper Project. Based upon all of the evidence in the record and cited in detail in this order, the Commission finds that in terms of long-term strategic value, compared to the other alternatives, the Project provides a combination of lower and more predictable fuel costs, available financial incentives, favorable environmental benefits, CO_2 capture and economic development benefits. All of these benefits are important to MPCo's customers and the State of Mississippi as a whole. The Commission also finds that the Kemper Project is the overall most economical solution available to fill the need determined by the Commission in Phase One. Based upon these findings, the Commission finds that MPCo met its burden of proving by substantial evidence that the present and future public convenience and necessity requires and will require the acquisition, construction, operation and maintenance of the Kemper County IGCC Project.

162. As discussed above, however, the Kemper Project, like any utility project, does present several potential risks to both MPCo and its customers; and the Commission is charged by the Act to ensure that these risks are appropriately balanced. The Commission finds that the balancing of these risks also requires the placement of conditions on the Company's certificate for the Kemper Project pursuant to the authority in § 77-3-13, each of which is supported by substantial evidence and is otherwise in the public interest.

VI. CONDITIONS TO CERTIFICATE

163. The Commission has described the risks that the proposed Project places upon customers and the Company.[270] Dr. Roach raised concerns that the Kemper Project could exceed its cost estimate by as much as 10% to 20%.[271] The Sierra Club's witness Mr. Schlissel also testified concerning the potential for cost overruns based upon cost overruns experienced with other utilities in other jurisdictions.[272] Several risk mitigation measures were suggested by the Commission, briefed by the parties, and discussed at length at the hearings.

164. At the hearings, Mr. Anderson testified on behalf of the Company concerning the Project design, cost estimates, performance assumptions, mining plan, lignite price and by-product revenues.[273] In both his pre-filed and oral testimony, Mr. Anderson explained the extensive experience that MPCo and Southern Company have in constructing large utility capital projects.[274] Based upon this experience and the FEED Study completed by the Company, Mr. Anderson expressed confidence in the various cost estimates, performance assumptions, contingencies and revenue assumptions used in the economic evaluation.[275] However, MPCo's witnesses consistently testified that it would not be in the best interest of customers for the Commission to require that MPCo guarantee the various estimates and assumptions used to evaluate the Kemper Project, because of the adverse impact to the Company's financial strength

---

[270] *See infra* Section V.F.

[271] Phase Two Hearing Transcript, p. 1888.

[272] Phase Two Direct Testimony of David Schlissel, (Dec. 7, 2009); Phase Two Hearing Transcript, pp. 1092-96.

[273] Phase Two Hearing Transcript, pp. 1129-1401.

[274] Phase Two Rebuttal Testimony of Thomas O. Anderson, pp. 2-5 (Jan. 5, 2010).

[275] *Id.* at 4.

and credit quality and the inability to make economic adjustments to the Project scope of design that increased the capital cost but made the overall Project more economic.[276]

165. At the conclusion of the hearings, the Commission encouraged MPCo to reconsider its position on the various customer protection measures discussed and voluntarily provide a proposal to the Commission concerning these issues.[277] In the Commission's February 11, 2010, order the Commission specifically requested risk mitigation proposals from all of the parties.

166. In connection with its filings on March 12, 2010, the Company provided a proposal to the Commission containing a number of customer protection measures, including but not limited to, a provision for cancellation of the Project, a cost cap, a performance penalty related to the TRIG™ gasifier, and an operational and cost performance-based plan.[278] The performance plan contains indicators that would measure the Project's heat rate, capacity, availability, fuel price and other costs, and adjust the Company's allowed return based upon actual performance as compared to estimates.[279]

167. Subsequently, the Company offered another suite of customer protection measures in its Motion for Reconsideration. While the Company proposed a construction cost cap of 20%, it still maintained that 100% recovery of CWIP financing costs beginning in 2012 and regularly scheduled prudence reviews were needed in order to obtain financing for the

---

[276] *Id.* at 12; *see also* Phase Two Hearing Transcript pp. 1393-1401, 1894-95.

[277] Phase Two Hearing Transcript, pp. 2413-14.

[278] *See* MPCo's Phase Two Post-Hearing Submission (Mar. 12, 2010).

[279] *See* MPCo's Revised Rate Schedule "CNP" (Mar. 26, 2010).

Project.[280] The Company's Motion also stated that the Commission's operational cost and performance parameters were too vague for the Company to properly evaluate.[281]

168. Through the issuance of this order, the Commission has decided to place specific conditions upon the certificate of public convenience and necessity being granted herein pursuant to its authority under § 77-3-13(3). Each condition is designed to address and mitigate one or more of the risks previously identified in this order and all conditions are supported by substantial evidence in the record. Moreover, MPCo has previously agreed to these same conditions as part of our granting the Final Certificate Order in June 2010. Finally, through the affidavit of Thomas O. Anderson, included with MPCo's proposed order submitted on April 2, 2012, the Company has confirmed its agreement with these conditions being attached to the certificate of public convenience and necessity issued herein. Based upon all of the foregoing, by agreement of MPCo and pursuant to our authority under § 77-3-13(3), the Commission, in its judgment, finds that the following conditions are in the best interest of MPCo and its customers and are required to satisfy and protect the public convenience and necessity.

A. Cost Caps

170. While the Company expressed confidence in its estimates, certain things can occur during the development, construction, and operation of a project of Kemper's magnitude that truly are outside the control of the Company. Moreover, the Company may be presented with opportunities to improve the overall benefits of the Project, which may result in changes in design and in construction plans and costs. Notwithstanding our previous orders in this matter, the Commission understands that the certificate process requires that the Company submit and

---

280 MPCo Motion for Reconsideration, p. 4 (May 10, 2010).

281 *Id.*

this Commission must consider "estimates" of the cost of certificated projects.[282] This Commission has made findings in this order based upon undisputed evidence in the record that MPCo's estimation process is reasonable. The Company is not authorized under Mississippi law to proceed through construction design or to enter into all of the required contracts for the Project before the Commission issues a certificate of public convenience and necessity for the facilities proposed. The primary purpose of 77-3-11, 77-3-13 and 77-3-14 is to prevent a regulated utility from spending substantial sums of money on a project before this Commission gets to review whether the public convenience and necessity actually requires it.

171. Still, the Commission must be able to rely upon the reasonableness of the estimates presented to it by a regulated utility and assure itself of the reasonable accuracy of those estimates for the benefit and protection of the ratepayer. To protect customers from cost increases, a cost recovery cap or guarantee was suggested by several parties. Under variations of a cap mechanism, the recovery of costs over the established cap would be limited or disallowed in the discretion of this Commission.

172. Section 77-3-14 requires a public utility to submit an estimate of construction costs, and the Commission must review and approve the estimate before granting a certificate allowing construction.[283] As to facilities treated under the Baseload Act, such as Kemper, "recovery of any construction costs incurred in excess of the amount estimated by the public utility in a certificate proceeding will be addressed by the commission in a proceeding after the generating facility is completed and commences commercial operation, upon petition by the

[282] MISS. CODE ANN. § 77-3-14 (Rev. 2011).

[283] MISS. CODE ANN. § 77-3-14(4).

public utility."[284] Thus, the law contemplates that cost overruns should be addressed by the Commission after they occur and the plant is placed into commercial operation. Consequently, the Company's approximate $2.4 billion estimate, in which MPCo expressed such confidence, serves as the first measure of cost recovery protection for ratepayers. Utilizing these traditional tools, the Company cannot recover any amounts in excess of $2.4 billion until such time as this Commission has scrutinized those costs for prudency, which will occur, at the Commission's discretion, upon petition of MPCo at such time after the Plant has been completed and entered into commercial operation. Estimates, although not required with great precision or detailed design, do have consequences for the Company. To recover anything beyond the estimated $2.4 billion, the Company must demonstrate to the Commission the prudence and necessity for such variation. If a cost estimate is conservative and if MPCo is confident in those estimates then exceeding the estimate should not be a necessity.

173. The Commission could stop with these legal protections in place and utilize further proceedings to address any cost overruns should they arise. Even so, the Commission finds that to better balance the risk between Company and ratepayer the Commission should establish a "hard" cost cap, an outer limit beyond which even prudent costs cannot be recovered from the ratepayers.[285] To be clear, this hard cap is an imposition on the Company and an additional protection to the ratepayer beyond what is required by law.[286]

174. The record contains substantial evidence regarding the risk and probability of cost overruns for the Kemper Project as well as the economic impact of various levels of cost overruns. The risk of overruns is detailed in Section V of this Order. The evidence of the

[284] MISS. CODE ANN. § 77-3-105(1)(d).

[285] *See* MISS. CODE ANN. § 77-3-13(3).

[286] *Id.*

economic impact of various overrun scenarios was provided by two parties: (1) MPC through a figure contained in the testimony of Mr. Thomas Anderson; and (2) Boston Pacific through 15 different economic evaluation tables contained its report. This evidence was also discussed and supported by the sponsoring parties during the Phase Two Hearings.

175. Mr. Anderson's testimony provided a figure that analyzed the margin over which Kemper was more economic than the Sweatt Combined Cycle Alternative (Sweatt Alternative) in terms of capital cost overruns for Kemper. The Anderson Figure indicated in the high gas scenarios Kemper could withstand between a $550 and $920 million capital cost overrun and still be equal to or better than the cost of the Sweatt Alternative over the forty-year life of the alternatives.[287] That range represents between a 23% and 38% Kemper economic advantage in favor of Kemper over the Sweatt Alternative.[288] According to the figure, Kemper's economic advantage decreases as natural gas prices decrease.[289] Thus, the Anderson Figure could support a construction cost cap between 0% and 38% over the $2.4 billion cost estimate, depending upon the scenario selected. However, as noted above, the Commission has declined to select any one scenario as the most probable.

176. Boston Pacific's Report contained 15 different tables comparing the relative economics of Kemper versus all other alternatives under various cost overrun assumptions.[290] Specifically, Boston Pacific assumed that the Kemper Project experienced a 10% cost overrun and a 20% cost overrun over the Company's $2.4 billion estimate and generated economic results versus the IPP bids and the Sweatt Alternative (Bid 19). As discussed earlier in this

[287] Figure 1 to Phase Two Rebuttal Testimony of Thomas O. Anderson, p. 11 (Jan. 5, 2010).

[288] *Id.*

[289] *Id.*

[290] *See* Tables E-15, E-16, E-17, E-18, E-19, E-20, E-21, E-22, E-24, E-25, E-26, E-27, E-28, E-29 and E-30 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

order, many of the Boston Pacific tables drop from primary consideration once this Commission makes certain strategic preferences. This same logic holds true for the Commission's establishment of a cost cap. Because of this Commission's preference for a long-term resource and evaluation methodology, all of the tables generated from the Modified Annuity method are removed from consideration.[291] This Commission's finding that the fixed gas bids lacked sufficient credibility eliminates several other Boston Pacific Tables from consideration.[292] After weighing the relative credibility of the various "strategic preferences" represented by the different Boston Pacific tables, Tables E-9, E-11, E-27 and E-29 remain for further review and analysis. Under base case assumptions, Kemper is the overwhelming winner, winning 16 of 20 scenarios.[293] Even assuming a 20% Kemper cost overrun, Kemper wins in 13 of the 20 scenarios.[294]

177. Several aspects of Mr. Anderson's Figure 1 and the assumptions contained therein cause this Commission to rely more heavily upon the Boston Pacific cost overrun evidence. The Anderson Figure generates capital cost overrun data by comparing two-self build alternatives—the Kemper Project and the Sweatt Alternative. This Commission has already detailed the several uncertainties associated with the Company's cost estimates for Kemper, many of which also apply to the Sweatt Alternative. In fact, the estimate for the Sweatt Alternative was even more uncertain than the Kemper Project estimate, because no site-specific design had taken place and the estimate was not based upon a FEED study. Instead, the Sweatt

---

[291] *See* Tables E-15, E-16, E-19, E-20, E-24, E-25, E-26, E-28 and E-30 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[292] *See* Tables E-17, E-18, E-21 and E-22 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[293] *See* Tables E-9 and E-11 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[294] *See* Tables E-27 and E-29 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

estimate was based upon the Company's Technology Data Book containing generic, high-level estimates generated from conceptual design and past combined cycle plants constructed.[295] These uncertainties create a strong possibility that the Sweatt Combined Cycle alternative, if actually constructed, will vary from the current Technology Data Book estimate. Although the Sweatt Alternative estimates are sufficient for the purposes of reviewing a certificate petition under the Act, such information is too general and incomplete to solely rely upon in establishing a hard cost cap, which is intended to disallow even prudent costs incurred in excess of the cap.[296]

178. Because this Commission recognizes the seriousness and significance of a cost cap, in order to reasonably rely on this information to establish an appropriate cost cap, the Anderson Figure 1 percentages would need to reflect a hypothetical 10% and 20% cost overrun experienced by the Sweatt Alternative. This additional analysis is not contained in the record, making the Company's evidence on this issue incomplete.

179. The Commission finds that there are additional concerns with the Anderson Figure. Once the Commission decided to elicit more market oriented proposals, i.e. the IPP bids, both Boston Pacific and MPCo evaluated these bids and the self-build alternatives using somewhat different inputs and methodologies, both of which this Commission found reasonable. When MPCo examined the IPP bids against its Sweatt Alternative, one asset sale bid performed very similarly to the self-build option.[297] When MPCo compared Kemper against this asset sale bid, Kemper was the dominant economic choice, prevailing in 12 of 16 scenarios and showing

---

[295] *See* Direct Testimony of F. Sherrell Brazzell, pp. 3, 6-7 (Jan. 16, 2009); *see also* Exhibit____(FSB-2) to the Phase Two Direct Testimony of F. Sherrell Brazzell (Dec. 7, 2009).

[296] The Commission notes that MPCo never proposed the Sweatt Alternative as an option to fill the Company's need so it is unreasonable at this stage to expect a more detailed estimate.

[297] Phase Two Supplemental Testimony of David F. Schmidt and Gary C. Rozier, p. 16, Figure 3 (Jan. 25, 2010).

cost savings in excess of $480 million dollars in 9 of 16 scenarios.[298] Kemper's performance against the competitive asset sale bid, and as compared against the Sweatt Alternative to the asset sale bid, shows Kemper producing cost savings significantly greater than those presented in the Anderson Figure.[299] MPCo's examination of the alternatives in Phase Two raises significant questions about the Anderson Figure for purpose of arriving at a cost cap.

180. Because more credible evidence presented by the Commission's independent expert, Boston Pacific, is contained in the record, this Commission finds it unnecessary to rely upon the Anderson Figure to support the cost cap established herein.

181. The Commission notes that the IPP bids do not suffer from the same capital cost uncertainties that utility self-build alternatives do, because the IPP bids represent the actual capacity cost that can be expected to be borne by customers.[300] This point was repeatedly argued by the IPPs as well as the Sierra Club throughout the Phase Two Hearings. In fact, the primary argument made in favor of the IPPs bids was that there was no construction cost risk borne by the customer, because the plants had already been constructed and the terms of the bid provided only limited opportunity for the bidder to flow capacity cost increases to customers.[301] This point was even conceded by the Company's witnesses.[302] Therefore, this Commission finds that the Boston Pacific cost overrun analysis is the more credible and more reasonable analysis to use

[298] *Id.* at 17, Figure 4.

[299] *Compare* Phase Two Supplemental Testimony of David F. Schmidt and Garey C. Rozier, pp. 16-17, Figure 3-4 *with* Phase Two Rebuttal Tesiomony of Thomas O. Anderson, p.11, Figure 1 (Jan. 5, 2010).

[300] *See* Report of Independent Evaluator, p. 2 (Jan. 25, 2010).

[301] *See, e.g.,* Phase Two Hearing Transcript, pp. 1083-86; *see also* Rebuttal Testimony of Rebecca Turner, pp. 13-15 (July 28, 2009).

[302] *See* Phase Two Hearing Transcript, pp. 1463-64.

in support of a construction cost cap, because it included the IPP bids as well as MPC's self-build Sweatt combined cycle bid.[303]

182. Boston Pacific's Evaluation Report establishes rather conclusively that under the strategic preferences selected by the Commission that Kemper still wins in the majority of scenarios, which are based upon a range of fuel forecasts and carbon compliance costs, even with a 20% capital cost overrun.[304] In support of his analysis, Dr. Roach specifically testified at the hearings that in his expert opinion a 20% cap would be reasonable.[305] Dr. Roach's primary support for this cap level is Table E-27 from the Boston Pacific Independent Evaluator Report:

> COMMISSIONER PRESLEY: Dr. Roach, I'd just like to follow up with a couple of questions. . . . Would you just enumerate for the Commission, when you say that the company should give some guarantees, that's your opinion. Tell us what those guarantees should be. What should we be looking for guarantee wise?
>
> DR. ROACH: I think this would the subject of negotiation. Let me try to be as –
>
> COMMISSIONER PRESELEY: Just some bright points in there would be helpful.
>
> . . .
>
> DR. ROACH: All right. Okay. So what I would do – if that table [Boston Pacific E-27] is your justification, then I would say – I would say to Kemper, again, I'm not signing a blank check. <u>What I'm going to do is you still do okay with even a 20 percent capital cost overrun. So I'm going to tell you today – but if it went</u>

[303] The Sierra Club argued on appeal that the Boston Pacific cost overrun evidence was improperly relied upon because the analysis did not include the Sweatt Alternative, which the Sierra Club claims was the "second best" alternative. It is this contention that the Sierra Club uses to support its assertion that the only proper evidence to use to support a cost cap is the Anderson Figure. The Sierra Club incorrectly interprets Boston Pacific's report. Boston Pacific's evaluation clearly included the Sweatt Alternative (i.e. Bid 19) as one of the bids evaluated. *See* Table D-1 of Appendix D to Report of the Independent Evaluator (Jan. 25, 2010); *see also*, Phase Two Hearing Transcript, pp. 1739-40.

[304] *See* Tables E-17 & E-18 of Appendix E to Report of the Independent Evaluator (Jan. 25, 2010).

[305] Phase Two Hearing Transcript, pp. 1882-84.

> beyond that, you would begin to lose.
>
> So I'm going to tell you today that I'm not going to entertain, once you're finished with this, the equivalent of anything above a 20 percent capital cost increase.
>
> I'm just not going to entertain it. I'm not going to tell you that any cost increase is prudent today, but I'm just giving you a warning up front I'm not going over that number.
>
> Now, you – can say to the company now, if you have a capital cost overrun but you offset that by lower lignite prices and you win a better deal there or higher by-product sales prices, I'll let you do that, but I'm telling you now that I'm not going to go above that.
>
> I also – that would be the cost cap. I would – I would have – beyond that, I would have the Commission have its own what I would call owner's engineer, owner's auditor. And I would have that auditor responsible to judge all the components of what the ratepayer is paying for, monitor cost overruns on capital, cost of lignite, as well as operating costs, as well as by-product sales. Is that –
>
> COMMISSIONER PRESELY: Those two main things, the cost caps and then some sort of independent engineer/auditor mechanisms.
>
> DR. ROACH: Right.[306]

The above quoted testimony of Dr. Roach was undisputed by any party in the case other than MPCo, which was advocating that no cap be implemented.

183. Based on all of the evidence cited above, particularly Boston Pacific Table E-27, this Commission finds that even with a 20% cost overrun the Kemper Project is more economic than the other alternatives presented in this case in a majority of the scenarios under consideration.[307] Therefore, this Commission finds that a 20% cost cap above the Commission-approved capital cost estimate constitutes a reasonable protection for customers against

---

[306] *Id.* (emphasis added).

[307] As noted herein, *supra* at pp. 70-71, the Boston Pacific analysis offers a conservative comparison of Kemper to alternatives. Meaning, benefits of Kemper are likely understated by comparison to the alternatives and the costs are likely overstated.

construction cost increases, while allowing for prudent deviations from the original cost estimate so as not to unduly punish the Company. In granting MPCo flexibility to exceed its original estimates for the distinct reasons set forth herein, the Commission is following the principle that a utility's obligation to act prudently always includes making investments that reduce total lifetime cost to the ratepayers. The Commission does not intend the construction cost caps to conflict with that principle.

184. This Commission finds that the cap established herein will adequately mitigate the risk to customers of a significant capital cost overrun, while allowing for a reasonable level of prudent deviation from the original approved cost estimate. This approach recognizes that because our certificate statutes require that estimates be provided before all final design, procurement and bidding can be conducted, the Company's estimates will not prove to be exact. Therefore, this Commission finds that the following cost cap conditions are reasonable and adequately balance the risks of the Company and its customers:

a. Construction Cost Cap: The Commission finds that a hard cap of 20% in excess of the net construction cost estimate of $2.4 billion for the items described in Exhibit____(TOA-1), Appendix B (excluding the lignite mine and CO_2 pipeline which are not included in the $2.4 billion estimate) is appropriate, provided that no amounts in excess of the overall estimate of $2.4 billion will be approved for recovery, unless and until this Commission reviews the prudence of those expenditures and the Company is able to justify such costs by demonstrating that they are prudent and required by the public convenience and necessity. Therefore, the total construction cost recoverable from ratepayers must not exceed $2.88 billion total, (which figure is net of government construction cost incentives ($296 million)), unless the cap is increased pursuant to the specific authority provided in this order.

b. Exceptions to the Construction Cost Cap: The Commission, in its discretion, will approve MPCo's request for an increase in the recoverable amount for any or all of the following reasons:

i. The Company demonstrates that the purpose and effect of the construction cost increase is to produce efficiencies that will result in a neutral or favorable effect on the ratepayers, relative to the original proposal.

ii. MPCo accompanies its proposed cost increase with an equal or greater revenue requirement decrease associated with one (1) or more of the other estimates (e.g., operational performance, sales of byproducts,) in its original proposal.

iii. To the extent the Commission does not allow 100% CWIP (which the Company assumed when making its $2.4 billion estimate), it will allow an increase in that figure to reflect the AFUDC cost that CWIP would have obviated.

iv. The Company demonstrates the occurrence of force majeure events such as Acts of God, natural disasters, war, terrorism, sabotage or similar catastrophes which were unavoidable through prudent utility practice or a change in law or regulation effective after the date of this Commission's May Order.

B. OPERATIONS COST AND REVENUES

179. The economics of the Project are dependent upon the accuracy of the Company's cost and performance estimates. Material deviations in O&M cost, lignite price, heat rate, availability, capacity and by-product revenues could have a significant impact on the comparable economics of the Project against other alternatives. Although the Company has testified that it is confident in its estimates, for the same reasons as the construction cost cap, namely, to mitigate the risk of costs exceeding reasonable levels (defined as the cost level in which the Company's

expert witnesses expressed confidence), the cost to ratepayers from operating the Kemper IGCC Project must not exceed the costs associated with the operational assumptions in MPCo's original filing (specifically, the assumptions concerning availability factor, heat rate, lignite heat content, and by-product revenues), unless the operational parameters are modified in a manner that makes the net result at least neutral in terms of costs to ratepayers over the life of the plant or unless the Commission finds that the public interest would be served by any variance from the Company's operating assumptions due to force majeure events such as Acts of God, natural disasters, war, terrorism, sabotage or similar catastrophes which were unavoidable through prudent utility practice or a change in law or regulation effective after the date of this Commission May Order. By "availability factor," we mean the availability to burn lignite, not natural gas, because the Company's ratepayer cost estimates for Kemper assume the low and stable cost of lignite rather than the volatile cost of gas, a contrast the Company emphasized. With these cost and revenue protections in place the ratepayer will not face the prospect of overpaying for an underperforming asset. Put simply, if Kemper doesn't perform as advertised then the ratepayers will not pay for it.

180. Within twelve months prior to commencement of commercial operation, and from time to time thereafter as MPCo or the Commission deems necessary, MPCo shall file with the Commission proposed rate schedules and tariff change(s) to implement the purposes of the above paragraph. The Commission will consider alternate proposals presented if it determines these proposals provide a better means of analyzing the Project's operating costs and revenues and protecting customers from undue risk.

C. USED AND USEFUL

181. Given the first of a kind technology risk associated with the Southern Company TRIG™ technology, cost and performance guarantees were also suggested. MPCo testified that it is usual for some original equipment manufacturers to provide some type of performance guarantee upon the purchase or license of a particular design or piece of equipment.[308] In fact, MPCo has been obtaining performance guarantees from third-party equipment vendors where practicable and these guarantees will inure to the benefit of the customers through rates if collected.[309] However, the Company claimed that a performance guarantee on the gasification technology would not be proper in this case, because the owners of the technology are not charging MPCo a licensing fee.[310] The Company also testified that the technology had been tested for over 15 years at the PSDF facility, including over a 1,795 test hours on Mississippi lignite, and, therefore, the risk of technology failure was low.[311] Several parties, including Dr. Schlissel testified that because the TRIG™ technology had never been used at the scale proposed, the risk of failure was largely unknown, and under the Company's initial proposal, this risk would be completely borne by customers.[312]

182. To address the first-of-a-kind technology issue (or any other issue that may arise), the Commission finds that nothing contained in this order or the Baseload Act shall diminish the Commission's authority to ensure that ratepayers do not pay for investments that are not "used or useful."[313] The Commission finds that the "used or useful" doctrine is distinct from the Baseload

[308] Phase Two Hearing Transcript, pp. 1341-42.

[309] *Id.*

[310] *Id.* at 1284-88.

[311] Phase Two Direct Testimony of Thomas O. Anderson, pp. 9-10 (Dec. 7, 2009); *see also* Phase Two Hearing Transcript, pp. 1288-90.

[312] Phase Two Direct Testimony of David Schlissel, p. 37 (Dec. 7, 2009); Phase Two Hearing Transcript, pp. 1216-17.

[313] *See, e.g.*, MISS. CODE ANN. §§ 77-3-33, -43.

Act and rejects and declines any application of the Baseload Act that would undermine the independent safeguards of the used and useful doctrine.

D. PLANT CANCELLATION

182. The Commission and certain other parties in the proceeding have raised concerns about the binding effect under the Baseload Act of prudence determinations made during construction.[314] Specifically, we are concerned about the risk that customers would be required to pay for all costs found to be prudent by the Commission prior to a decision by the Commission or Company to cancel the Project for any reason. Therefore, the Commission wishes to make clear that any determination of prudence made by the Commission in connection with the Kemper Project shall not diminish the Commission's authority under Miss. Code Ann. § 77-3-105(1)(e), providing that in the context of an abandonment or cancellation without Commission approval, the Commission shall:

> "determine whether the public interest will be served to allow (i) the recovery of all or part of the prudently incurred pre-construction, construction and related costs in connection with the generating facility and related facility, (ii) the recovery of a return on the unrecovered balance of the utility's prudently-incurred costs at a just and reasonable rate of return to be determined by the commission, or (iii) the implementation of credits, refunds or rebates to ratepayers to defray costs incurred for the generating facility."

E. GOVERNMENT INCENTIVES

183. MPCo's Petition assumes the availability of various government incentives, such as loan guarantees, grants and tax credits. MPCo has stated that based on its research of these

[314] The Commission finds that the Baseload Act is enabling and not mandatory. Nothing in the Baseload Act is meant to remove minimum ratepayer protections such as the "used or useful" doctrine. The Commission reiterates its finding that the used or useful doctrine is distinct from the Baseload Act and rejects and declines any application of the Baseload Act that would undermine the independent safeguards of the used and useful doctrine. The used or useful doctrine is, and remains, a separate protection or potential upper limit on cost recovery.

matters and its communications with relevant government authorities, it is confident of these amounts. There is risk, however, that these amounts will not be available, thereby raising Kemper's cost to customers. Should any portion of these amounts become unavailable, the Commission will allow recovery of the resulting increase in Kemper cost, if MPCo demonstrates: (a) it has made best efforts to procure the incentive before it became unavailable, and (b) the resulting increase in ratepayer cost is consistent with the public interest. If MPCo is successful in obtaining additional federal funding for the Kemper project, it shall file a Petition with the Commission notifying the Commission of the amounts and details of such funding.

F. ENVIRONMENTAL PERMITS

184. The construction of Kemper requires environmental studies, permits and other approvals. MPCo shall exercise diligence in obtaining the necessary permits and approvals and report to the Commission the receipt of the approvals and permits as soon as practical, provided that the Company shall not commence construction until it has obtained those permits necessary for the commencement of construction of the project. Any legal challenges to such permits shall not prevent the Company from moving forward, so long as the Company keeps the Commission informed as to the status of such challenges.

G. PROJECT VIABILITY

185. MPCo has a continuing obligation to ensure that Kemper is in the public interest. Pursuant to Miss. Code Ann. § 77-3-33 and applicable case law, MPCo has an obligation to take all actions necessary to serve its retail ratepayers at a just and reasonable cost. That obligation includes using its expertise to ensure that the path that it has urged continues to be the best path. The Commission's granting of a certificate does not diminish this obligation. The first-of-a-kind nature of this project, its unprecedented size and cost, and the uncertainty concerning the cost of

alternatives to Kemper, call for special measures to ensure that the certificate issued is consistent with the public convenience and necessity. The Commission therefore makes explicit what is implicit: MPCo has a continuing obligation to ensure that Kemper remains consistent with the public convenience and necessity, in light of feasible alternatives. MPCo shall therefore file with the Commission (a) annually, starting with May 1, 2011 and ending on May 1, 2014, (b) with each request for a prudence determination, and (c) at any other time that the facts require, a report that supports MPCo's continuing conclusion that Kemper remains consistent with the public convenience and necessity. The Commission finds that this economic viability analysis addresses concerns raised by intervenors regarding changing natural gas prices.

VII. ANALYSIS OF COST TO CUSTOMERS

A. APPLICATION OF BASELOAD ACT

186. In its Certificate Filing, MPCo requested that the Commission exercise its authority to implement the provisions of the Baseload Act in connection with its approval of the Project. Specifically, the Company requested that the Commission find, among other things, (i) that the Project constitutes a "generating facility" as defined in the Baseload Act; (ii) that the Company's pre-construction activities and the costs incurred and to be incurred in connection therewith are reasonable, necessary, prudent, and in the public interest; (iii) that MPCo's prudently incurred pre-construction, construction, operating, and related costs in connection with the Project be included in MPCo's rate base and rates, as used and useful components of furnishing electric service; (iv) that the Company's proposed recovery of financing costs on CWIP in rate base is just and reasonable and should be approved; and (v) that the recovery mechanism proposed by the Company, including the establishment of periodic prudence reviews for the Project on a quarterly basis is just and reasonable and should be approved.

187. The Commission has carefully reviewed the provisions of the Baseload Act and the characteristics of the Kemper County IGCC Project as proposed by MPCo. Based upon the Company's Certificate Filing, including the extensive information submitted describing the characteristics of the Project, and based upon the substantial evidence presented in the record in this proceeding, we find that the Kemper County IGCC Project constitutes a "generating facility" as defined in § 77-3-103(a) of the Baseload Act. Specifically, we find that:

a. the Project is a coal gasification, clean coal project that will generate in excess of 300 MW or greater of electric power;

b. the Project will be owned and controlled in whole or in part by MPCo, an electric public utility certificated by the Commission in Docket No. U-99, as supplemented and amended from time to time, to operate within a certificated electric service area in Mississippi;

c. the Project is intended, in whole or in part, to serve retail customers of MPCo in Mississippi; and

d. the Project utilizes technology to reduce or minimize regulated air emissions, including CO_2, which the Commission finds is likely to become a regulated air emission.

B. RECOVERY OF CONSTRUCTION FINANCING COSTS

188. The Commission recognizes that building baseload generating capacity such as the Project requires significant capital investment and takes several years to complete. We further recognize that because the uncertainty created by the magnitude of cost, the length of construction period and the traditional two-step process to obtain recovery, financial markets and credit rating agencies are requiring increased legislative and regulatory assurances of cost recovery. In passing the Baseload Act, the Legislature acknowledged that these difficulties

would prohibit the construction of baseload generation without increased certainty of cost recovery. In order to facilitate public utilities' ability to finance and construct baseload generation, the Legislature authorized the Commission to utilize an alternate method of cost recovery for certain baseload generation when it is in the best interest of customers and the public to do so.

189. The Company testified that maintaining a strong 'A' credit rating will sustain the Company's low cost of financing, permit the Company to successfully construct the Project and is in the best interests of the Company and its customers.[315] A credit rating downgrade would increase MPCo's cost of capital, not just for this Project, but for the Company's entire business, and make access to capital markets more difficult.[316] Any credit downgrade will make construction of the Project more difficult.[317] For these reasons, the Company testified that it will not be able to proceed with this Project, unless the Commission allows recovery of 100% of the financing costs on CWIP, provides a periodic and expedited prudence review process, and establishes a special rate mechanism for cost recovery.[318] Ms. Turnage testified that this approach reduces the overall cost to the customer and allows the Company to maintain the financial strength needed to complete the Project and make the necessary investments required in MPCo's ongoing business of providing electric service.[319] This proposed financing and cost recovery plan would provide the best protection against a credit downgrade during construction.

---

[315] *See* Phase Two Direct Testimony of Frances Turnage, pp. 6-7 (Dec. 7, 2009).

[316] *Id.* at 3-4.

[317] *Id.* at 4-5.

[318] *Id.* at 4-6, 18.

[319] *Id.* at 3-5.

190. The Baseload Act grants the Commission the authority to use ratemaking that enables the timely recovery of the financing costs on the construction expenditures during construction, including a current return on CWIP in rate base. The primary purpose of this legislation and one of the primary reasons why the Commission would consider such an option is to save Mississippi retail customers money. The Company projects that the ability to collect the financing costs of the Project timely during construction would save retail customers between $500 and $600 million over the forty-year life of the Project.[320]

191. The Commission is committed to helping the Company maintain its strong 'A' credit rating by implementing measures to help sustain when reasonable and practicable the Company's currently strong quantitative and qualitative credit measures. To do so, the Commission must provide the Company enough cash flow during the construction period that is reasonably required to maintain the credit metrics for a strong 'A' credit rating. The Company testified that even with 100% recovery of financing costs on CWIP, its credit metrics will temporarily fall below the 'A' category rating.[321] However, Mr. Fetter testified that sustaining or enhancing MPCo's quantitative measures through supportive regulation would likely prevent a credit downgrade during construction.[322] This evidence is undisputed by any party.

192. While §77-3-105(1)(a) itself does not state a standard, the Commission has determined its authority to allow a current recovery of financing costs on CWIP is bounded by the requirement of §77-3-33, that rates be "fair, just and reasonable." The Company therefore should receive recovery of construction costs on CWIP to the extent, and only to the extent, necessary to ensure that electric rates meet this standard.

[320] *Id.* at 17-18.

[321] Phase Two Hearing Transcript, pp. 2178-80.

[322] *Id.*

193. Applying this principle to the record evidence, the Commission finds that although the Company's arguments for a recovery of financing costs on CWIP have merit conceptually, its request for a current recovery, starting in 2012, of 100% of financing costs on CWIP without any potential for adjustment as conditions materially change is not appropriate. Further, even if present conditions support current recovery of 100% of financing costs on CWIP, there is no reason to assume those conditions will persist, without change, for the entire construction period. The necessity and desirability of allowing recovery of financing costs on CWIP will vary as financial conditions vary. The strength of the national economy; the availability of capital and its cost generally; the financial community's perceptions of the utility industry, of Southern Company generally, and of MPCo's operations other than Kemper; -- all these factors will affect the necessity and desirability of CWIP. Committing ratepayer dollars to CWIP, without regard for these changing factors, and without the ability of the Commission to review such changing factors, could result in higher costs to customers than may be necessary.

194. The Commission understands that there can be positive benefits associated with CWIP, and desires that the Company remains in a financial position to fund the construction of the Project as well as the remainder of its on-going business operations at the lowest practical cost to customers. The Commission therefore, finds and adopts the following CWIP treatment for the Project:

For 2010 and calendar year 2011, no CWIP for the Project will be included in retail rate base and no retail financing costs will be recovered during 2010 and 2011 for any of the construction costs incurred for the Project through 2011. The Company shall accrue AFUDC in 2010 and 2011. The Commission bases its decision for this recovery treatment in 2010 and 2011 on the information provided by the Company in its Motion. Specifically, the Company's additional allocation of $279 million more in Phase Two investment tax credits and its stated expectation of receiving authority to advance the recognition of $245 million of CCPI2 funds for construction cost reductions,[323] and in an effort to allow the Mississippi economy to rebound from the recent recession, the Commission finds that there is no longer a compelling reason to provide a current return of financing costs on CWIP through 2011.

For calendar years 2012, 2013, and 2014, the Company is hereby authorized to include 100% of all construction costs (subject to prudence reviews as provided herein) in CWIP for the purpose of allowing recovery of the financing costs therein, provided that the amount of CWIP allowed is (i) reduced by the amount of any government construction cost incentives received by the Company in excess of $296 million to the extent that such amount increases cash flow for the pertinent regulatory period and (ii) justified by a showing that CWIP allowance will benefit customers over the life of the plant.

As part of its annual rate filings during construction beginning for the 2012 regulatory period, the Company shall present its CWIP return requirements for the project year (based upon 100% CWIP adjusted for government construction cost incentives described in the above paragraph) and shall include the Company's then current credit ratings from Moody's, Fitch's and Standard & Poor's. If the Company's credit rating has been downgraded below an "A" rating by any of the three rating agencies, the Commission may require the Company to submit additional information supporting its inclusion of a current recovery of financing costs on CWIP. In such event, the Commission may, based upon substantial evidence, make a finding that is specific to current conditions and may only adjust such amounts up or down based upon the evidence presented after notice to the Company and after an opportunity to be heard.

[323] MPCo's Motion for Reconsideration, p. 31 (May 10, 2010).

195. Because the statute limits CWIP recovery to a return on actual prudent costs, rather than estimated costs, the following true-up procedure is necessary. After the close of each period during which CWIP return has been earned, the Company will report its actual expenditures. The Commission then will determine the portion of actual expenditures that were prudent expenditures. The Commission then will adjust rates for the next period to correct any discrepancy in the prior period. The mechanism thus will result in the ratepayers paying no more than MPCo's actual financing costs associated with prudent actual capital expenditures through the period.

196. The Commission will not allow a current return on CWIP beyond May 1, 2014, unless the Company has demonstrated that such extra CWIP recovery is consistent with the conditions set forth in the Final Order. In no case shall the Commission allow the recovery of CWIP return on amounts exceeding the Company's approved estimate[324] or prudent construction costs, whichever is less.

C. PRUDENCE REVIEWS AND DETERMINATIONS

197. The Company has testified that timely and systematic reviews are essential to achieving the goals of the Baseload Act and preserving MPCo's financial strength. Absent periodic prudence reviews, MPCo's risk profile would significantly increase due to the significant portion of costs incurred by MPCo for which cost recovery is still uncertain. Ms. Turnage and Mr. Fetter both testified that such an increase in risk would adversely impact the Company's credit quality such that one or more downgrades could be expected and an increase in the cost of capital would result.[325] No party provided testimony at the hearings to contradict

[324] *See* MISS. CODE ANN. § 77-3-105(d).

[325] Phase Two Hearing Transcript, p. 2178.

any of the Company testimony concerning the effect of prudence reviews on the Company's credit rating.

198. As authorized by Miss. Code Ann. §77-3-105(2)(a), added to our statutes by the Baseload Act, the Commission will conduct periodic prudence determinations, on a schedule to be determined by the Commission in Docket No. 2011-UN-135. The Company requested in its original proposal that these determinations occur quarterly. To determine prudence, the Commission must have sufficient perspective concerning the reasons for particular costs, the effectiveness of cost decisions, and the alternative ways to incur costs. That perspective does not always come into focus at pre-set time intervals; it depends on surrounding facts. The Commission recognizes the benefits associated with giving MPCo certainty about cost recovery, and find that periodic prudence reviews are reasonable and necessary for the successful development of the Project and the implementation of CWIP rate recovery under the Baseload Act. The Commission will take those benefits into account in determining the schedule for prudence determinations.

199. Regardless of the schedule for prudence determinations, the Commission will establish a procedure for independent monitoring of cost accounting so that the Commission has full and current information of what dollars are spent and for what purpose. The Commission therefore will establish filing requirements including, in part, variance reports and ongoing analysis of resource options. Pursuant to Miss. Code Ann. §77-3-105(2)(b), added to our statutes by the Baseload Act, the reasonable costs of Commission and Staff hired monitors will be borne by MPCo and recovered from ratepayers.

D. KEMPER PROJECT RATE IMPACTS

200. Pursuant to Appendix "A," Schedule 3 of the Commission's Rules, the Company submitted in Phase Two significant documentation and data in both public[326] and confidential[327] form related to the estimated rate impacts of the Kemper Project. The Company submitted projected annual revenue requirement calculations over the life of the Kemper Project containing several different assumptions.[328] The underlying rate and revenue requirement data and information is presented generally in Ms. Turnage's testimony,[329] and more specifically in MPCo's response to data request Entegra 3-5.[330] In its response, MPCo estimated that its retail customers would experience rate increases of 5% in 2011, 6% in 2012, 9% in 2013 and 10% in 2014 (first year of commercial operation) but would begin decreasing in 2015.[331] In 2014, the cumulative impact of the Kemper Project on rates would be approximately 30% compared to 13% for a natural gas alternative; however, after that date the impact for Kemper begins to decline as the natural gas alternative continues to rise.[332]

[326] *See* Phase Two Direct Testimony of Ms. Frances Turnage, pp. 9-12 and Figure 1 thereto (Dec. 7, 2009); MPCo's Responses to Entegra 4-3, 4-5, 4-6, 4-13 (Jan. 27, 2010); MPCo's Responses to Boston Pacific 3-7, 3-12, 3-13, 3-14, 3-17, 3-19, 3 21, 3-23, 3-24, 3-25, 4-2a (Jan. 8, 2010 and Jan. 22, 2010); MPCo's Responses to MPSC 4-2, 4-5 (Jan. 26, 2010); and MPCo's Non-Confidential Responses to MPUS (LA) 2nd, 3rd, 7th, 8th, 9th and 10th Set of Data Requests (Apr. 17, May 28, Dec. 4, Dec. 8, Dec. 11, 2009 and Jan. 26, 2010) concerning detailed pre-construction costs.

[327] *See* Exhibit____(FT-12); Exhibit____(FT-13); Exhibit____(FT-14); Exhibit____(FT-15); Exhibit____(FT-16) (Dec. 7, 2009); MPCo's Response to Boston Pacific 3-15, 3-22a, 3-27 (Jan. 8, 2010); MPCo's Responses to MPSC 4-18, 4-19, 4-20 (Jan. 26, 2010); and MPCo's Confidential Responses to MPUS (LA) 2nd, 3rd, 7th, 8th, 9th and 10th Set of Data Requests (Apr. 17, May 28, Dec. 4, Dec. 8, Dec. 11, 2009 and Jan. 26, 2010) concerning detailed pre-construction costs.

[328] *See* Exhibit____(FT-12); Exhibit____(FT-13); Exhibit____(FT-14); Exhibit____(FT-15); Exhibit____(FT-16) (Dec. 7, 2009).

[329] *See supra* notes 326 and 327.

[330] MPCo's response to Entegra 3-5 was originally filed confidentially but was later made public.

[331] The Commission notes that MPCo's rate impact estimates in this response assumed 100% Baseload Act rate treatment beginning in 2011, which was not ultimately approved by the Commission. Attachment A to MPCo's response to Entegra 3-5.

[332] *Id.*

201. The Company also provided specific rate increase percentages on annual basis in several of the different scenarios considered in the economic evaluation.[333] These impacts were presented as a differential between the Kemper County IGCC alternative and relying on a natural gas alternative to fill the Company's identified need. This was conducted for 8 of the scenarios considered in the economic evaluation. In summary, the cumulative net impact of the Kemper alternative on retail rates in the reference case compared to the expected rate increases associated with a self-build natural gas alternative is approximately 8% higher than this alternative in 2014, continues around that level through 2020, and then decreases until around 2024, when at that point, and for the rest of its useful life, the rate impacts of Kemper are lower than the alternative.[334]

202. These rate impacts are estimations and are still subject to Commission ratemaking proceedings, which include rate design issues, potential disallowances and other dynamics. That is to say, the rate impacts are what the Company expects or may ask; it is not necessarily the rates that will be approved.[335]

203. MPCo currently serves approximately 186,000 retail customers in 123 municipalities and unincorporated communities in southeastern Mississippi. Despite learning about the expected up-front rate impacts of the Kemper Project, all of the comments from MPCo's larger customers support the Kemper Project. In fact, the Commission has received over fifteen letters of support from large commercial and industrial customers of MPCo and other governmental entities or business trade groups that represent the interests of many of

[333] *See* Figure 1 to Phase Two Direct Testimony of Frances Turnage, p. 12 (Dec. 7, 2009).

[334] *Id.*

[335] On appeal, Sierra Club, as well as some media outlets, claimed that Kemper would lead to a 45% increase in rates. The Commission finds no support for that position in the record. As shown herein, the projection peaks at a possible 30% impact in 2014 and then begins to decline.

MPCo's customers.[336] Just as important, however, is the fact that the Commission has not received one comment from a large commercial or industrial customer of the Company against the Kemper Project. History has shown that many of MPCo's large customers will intervene and oppose those measures that they believe will be detrimental to their interests.

204. SMEPA, MPCo's largest and most sophisticated customer, fully supports the Project and even provided pre-filed and hearing testimony in this proceeding. SMEPA will be responsible for approximately 30% of the cost of the Project if built through its FERC approved wholesale rates, and is working to purchase an ownership interest in the Project above and beyond this cost responsibility. Therefore, SMEPA has a significant interest in ensuring that MPCo maintain the most reliable and lowest cost electricity possible. As a public utility, SMEPA understands the importance of Kemper in accomplishing those goals:

> In order to keep costs stable, utilities must maintain a diverse mix of generating resources. This requires evaluating resource alternatives, considering risks and maintaining a willingness to make decisions to minimize risks. Based on SMEPA's preliminary evaluation of the proposed IGGC project, we believe that the project is a viable available alternative to minimize risks and to help provide long-term rate stability for MPC's wholesale and retail customers. In addition, SMEPA is evaluating a joint ownership position in the project as an option to minimize risks and provide long-term rate stability to SMEPA's members.[337]

205. Based upon this evidence in the record, the Commission finds that adequate rate impact information was provided by the Company. We also find that the evidence contained in the record from many of MPCo's customers, including several large commercial and industrial customers, supports a finding that the rate impacts of the Kemper Project, while significant in the

[336] Phase One Late Filed Exhibit Nos. 17 & 18; Phase Two Late Filed Exhibit No. 32.

[337] Phase Two Direct Testimony of Nathan Brown and John Carley, p. 15 (Jan. 5, 2010).

short-term, are outweighed by the long-term benefits provided by the Kemper Project as detailed above.

E. Rate Schedule "CNP"

205. In connection with its Certificate Filing, the Company originally requested that the Commission approve its proposed Rate Schedule "CNP". The proposed rate schedule would implement the provisions of the Baseload Act by adjusting rates annually, on a projected basis, pursuant to a filing made by the Company in August of each year. Throughout the proceeding, Rate Schedule "CNP" was revised several times by the Company to address various issues identified. Pursuant to the previous orders issued by the Commission, the Company has filed for approval of Rate Schedule "CNP-A" and Rate Schedule "CNP-B" in Docket No. 2011-UN-135. The approval of these rate schedules will be addressed by the Commission in that docket.

F. Approval of Prudently Incurred Pre-Construction Costs

206. In Docket 2006-UN-581, the Commission authorized MPCo to charge costs associated with its generation planning, screening, and evaluating of its next generation option to a regulatory asset. These costs were to remain in the regulatory asset account until the earlier of June 30, 2008, or upon certification of the next generation resource. The Commission subsequently amended the order to defer the beginning of the amortization period to January 1, 2009. On April 6, 2009, the Commission issued an order consolidating Docket 2006-UN-581 with the docket at hand. In the April 6 Order, the Commission ordered that all of MPCo's pre-construction costs were to be charged to and remain in the regulatory asset until the Commission made findings as to the recovery of MPCo's prudent expenditures in this Docket. The Commission requested the Staff to continue its on-going investigation of the prudence of MPCo's pre-construction expenditures. During the Phase Two Hearing, the Commission heard

evidence on this issue. The Commission finds that it was prudent for MPCo to perform the pre-construction activities at issue to meet its duty to provide adequate, reliable electric service to its customers.

207. Larkin was engaged by the Staff to perform a detailed review and verification of charges for preconstruction costs that were recorded into the regulatory deferral account to evaluate the usefulness for inclusion in customer rates.

208. The record reflects that Larkin found that MPCo, at the end of March 2009, had recorded $50,470,935 of pre-construction costs. Larkin further found that $4,470,098 of the costs they reviewed were inadequately documented, questionable or inappropriate and recommended that the Commission remove these costs from MPCo's March 31, 2009 pre-construction cost balance.

209. At the hearings, MPCo's Comptroller, Ms. Cynthia Shaw, offered testimony attempting to justify the value provided by MPCo's service company affiliate in terms of the relative costs of hiring third parties and the reasonableness of the rates paid to SCS for its engineering and related services, including the fact that those services are invoiced "at cost" in accordance with FERC rules. Ms. Shaw testified that the use of SCS for engineering work on the Kemper Project was beneficial to customers and therefore, SCS cost, including variable pay and overheads, should be allowed for recovery. SCS, like independent third-party contractors, includes variable pay and overhead costs in its billings. Ms. Shaw testified that unlike other contractors, SCS does not charge a profit. MPCo asserted that the exclusion of SCS variable pay and overheads from recovery would be unreasonable and without merit and would motivate MPCo to hire more expensive engineering firms.

210. The Commission finds the testimony of Mr. Smith to be persuasive and adopts his recommendation. Pursuant to our authority to allow recovery of prudently incurred costs, added to our statutes by the Baseload Act, we will allow recovery of these costs. However, we reserve the authority to revisit the issue of the recovery of SCS variable pay and overheads in a future proceeding. Specifically, the Commission finds that $46,000,837 out of the total $50,470,935 in pre-construction costs are reasonable and prudent and we adopt Mr. Ralph Smith's testimony to that effect. Those prudently incurred pre-construction costs, to the extent allowed under FERC and Commission accounting rules and under generally accepted accounting principles, should be capitalized to the applicable capital work order for the project. To the extent such costs cannot be capitalized under the applicable accounting rules, we find that such costs should be amortized through an appropriate rate schedule to be determined in a subsequent proceeding. We note Ms. Shaw's testimony regarding SCS variable pay and overheads and reserve our authority to revisit and address such costs in a future proceeding regarding review of pre-construction costs incurred from April 2009 through the month of the Commission's Order.

VIII. MISCELLANEOUS MATTERS

A. APPROVAL OF PROJECT ESTIMATE

211. Under § 77-3-14(4) "no certificate shall be granted unless the commission has approved the estimated construction costs." According to the Company's Certificate Filing, the total estimated cost to construct the Kemper plant is equal to $2,399,700,000, net of incentives and excluding certain items of costs that were still being considered by MPCo, such as the lignite mine and CO_2 pipeline. No other estimate is contained in the record; however, as discussed above, some concerns relating to certain aspects of the estimate were raised in the testimony. The Commission finds the Company's construction estimate is reasonable and hereby approved

solely for the purpose of granting a certificate of public convenience and necessity. The Commission's approval of the cost estimate is not a finding of prudence and shall not be construed in any way as approving the prudence any of the costs contained therein, unless specifically addressed in this or subsequent orders of the Commission issued after a prudence review in compliance with Mississippi law. This approved estimate may only be amended by subsequent order of the Commission upon a petition by the Company and upon a finding based on substantial evidence that such amendment is reasonable, beneficial to customers and in the public interest.

212. The Commission is required under Miss. Code Ann. § 77-3-13(4) "to ascertain that all labor, property or services to be rendered for any proposed project will be supplied at reasonable prices." As provided above, the Company's Project estimates were thorough and based upon reasonable assumptions that are typical for projects of similar scope and size. The Company provided testimony that the engineering, procurement and construction portion of the Project would be conducted and managed by SCS, an affiliate of MPCo, who provides cost-based services to all of the Southern Company operating companies. Mr. Anderson and Ms. Shaw specifically testified that the rates and charges for SCS were reasonable and below prevailing industry rates for similar services.[338] No party challenged the specific assumptions made by the Company regarding its estimates for labor, property or services. Therefore, the Commission finds that the Company's estimates contain reasonable assumptions for labor, property or services, and, in accordance with the procedures set out below, the Commission and

---

[338] Phase Two Rebuttal Testimony of Cynthia Shaw, pp. 9-10 (Jan. 5, 2010); Phase Two Rebuttal Testimony of Thomas O. Anderson, p. 5 (Jan. 5, 2010).

Staff will continue to monitor the Company's construction progress to ensure that all costs are reasonable and prudent.

B. MONITORING PLAN

213. Under § 77-3-14(5), the Commission is required to maintain an ongoing review of the construction of the Project. We find that our statutory monitoring duties and rights provide one of the most important risk mitigation measures available to protect customers. Given the unprecedented scope and cost of the Project, the Commission believes that the public interest is served by retaining certain experts to assist the Commission in its monitoring duties. In fact, the Baseload Act specifically authorizes both the Commission and the Staff to retain such experts to assist them. The Independent Monitor shall assist the Commission in its statutory duties by monitoring the progress of the Project, reviewing costs and plans, advising on questions of prudence, and providing reports, from time to time, on the status and viability of the Project. The Independent Monitors may also have responsibilities concerning review of operations once construction is completed.

214. The Commission has and will retain these experts by contract, the Company will pay these experts' fees as approved by the Commission, and the Commission will expeditiously allow recovery from ratepayers of the Company's payments. MPCo shall file a Rider Schedule that will ensure timely recovery of these incurred costs.

215. The Commission will develop procedures for how these Independent Monitors will submit reports to the Commission, and how the Company and others will comment on such reports, at a later time.

216. In addition to the Commission's monitoring duties, the Staff is hereby directed pursuant to § 77-3-13(4) to monitor and inspect periodically the progress of Project construction.

Included in this duty to monitor, the Staff is directed to submit a written progress report to the Commission concerning any deviations or variances in the Project scope, cost schedule, and any other significant item found by the Staff that may affect the Company's ability to complete the Project on schedule and within the approved cost estimate. The Staff will make its reports public on a schedule set by the Commission. The Commission expects its consultants and the Staff to coordinate their actions and share the information. The Staff may retain and compensate experts for this purpose in like manner as provided herein for the Commission.

217. If the U.S. DOE provides loan guarantees for the project, it may require similar oversight and review of project costs. To minimize cost to customers, it is our intent to coordinate with DOE to the extent practical to avoid duplication and unnecessary work. To facilitate that coordination, the Commission orders MPCo to report to the Commission on DOE oversight activities as they become known.

218. All of the consultants retained by the Commission and Staff in this proceeding is being done under the authority of § 77-3-105(2)(b). The Commission will require all independent consultants and monitors to execute any confidentiality and nondisclosure agreements the Commission deems necessary to protect information legitimately asserted to be proprietary or trade secret information related to the project.

219. MPCo shall provide and maintain, at its offices and at project construction site, office space and facilities sufficient to accommodate the Commission and Staff monitoring functions discussed here.

220. MPCo shall allow the Commission's experts and Staff's experts access to any information or observations about the plant and its operations, and to key personnel employed or retained by MPCo, to the extent deemed necessary by the Commission, the Staff or their experts.

MPCo shall ensure that any contractors it retains agree to grant comparable access to the Commission's experts and the Staff's experts.

221. Pursuant to § 77-3-14(5), MPCo is hereby directed to submit monthly written reports, with sufficient copies, to the Commission, the Staff, their respective consultants and any party of record requesting a copy, detailing the actual Project-related costs incurred in the preceding month (Monthly Cost Report). The purpose of the Monthly Cost Report is to provide the sufficient information regarding the costs incurred on the Project to allow the Commission, Staff and their consultants to adequately and timely audit such costs and monitor the status and progress of the Project. The Monthly Cost Report shall be in a form and manner as prescribed by the Commission so as to standardize the Project information and assist the Commission, Staff and their consultants in their monitoring duties.

C. THE MISSISSIPPI ECONOMY

222. The record in this proceeding demonstrates and quantifies the significant economic benefits to the State of Mississippi from the construction of Kemper. Separate and independent studies assessing the economic impact of Kemper were performed by the John C. Stennis Institute of Government of Mississippi State University and by Ernst & Young.[339] By way of illustration, the Ernst and Young study estimated the statewide economic impacts as follows: Direct Economic Impact—310 permanent jobs, $28 million of additional Mississippi income during the first full year of operations, and royalty payments of $18 million that same year; Indirect Economic Impact—703 jobs and $37 million in personal income; Total Ongoing Economic Impact—1,013 jobs and $67 million in personal income to Mississippi residents from 2013 to 2022; Fiscal Impact of Operations--$17.1 million in additional state tax revenues and

[339] MPCo Response to Entegra Data Request 1-39 (April 8, 2009).

$8.3 million of local tax revenue, increased state tax revenue of $3.5 million and $.7 million local tax revenue, resulting in total state tax revenues of $20.6 million and local tax revenues of $9 million during the first ten years of operation.[340]

223. In light of the contribution that Mississippi ratepayers will make to the construction of this plant, and in light of the risks that this project involves to our ratepayers, it is important that these and other types of benefits accrue to the state. To that end, the Commission therefore encourages MPCo to utilize Mississippi labor, resources and services during the design, procurement, construction and operation of this project, to the extent consistent with its legal obligations.

D. Remaining Procedural Matters

224. Thomas A. Blanton filed a Motion to Intervene out of time on March 21, 2012. Mr. Blanton's motion was filed over three years after the Company's initial Certificate Filing. Proper notice of these proceedings was provided as required by law, and, in fact, the Commission provided two separate opportunities to intervene in Phase One and Phase Two. Mr. Blanton chose to ignore both opportunities. Further, the Commission's Rules require that motions to intervene out of time show good cause for why the movant is out of time.[341] Mr. Blanton's motion fails to provide any reason for his gross tardiness. Finally, as explained above, the Commission has determined that no additional evidentiary hearings are necessary, and this Final Order on Remand resolves all remaining contested issues in this matter. Therefore, Mr. Blanton's motion is hereby denied.

---

[340] *Id.*

[341] Rule 6.121(5).

225. During the appeal of this matter, the Sierra Club claimed that the Commission failed to rule on a past motion filed by the Sierra Club during Phase Two related to the confidential nature of certain data and information submitted by MPCo in support of its Certificate Filing. A review of the record indicates that the Sierra Club's attorneys and expert witnesses were provided the confidential information prior to the Phase Two Hearings, and were therefore, not prejudiced during the hearings. In addition, some, if not all, of the confidential rate information that was subject of the Sierra Club's motion has since been made public through various public records requests. Finally, the Commission opened a rulemaking docket (Docket No. 2010-AD-259), wherein the Commission implemented significant revisions to the rules governing the filing of confidential information. This revised rule addresses the public policy concerns expressed in the Sierra Club's motion. Sierra Club's request appears to be moot, or at least not germane to the Commission's present task. To the extent any procedural issues remain outstanding from the Sierra Club's motion, they are hereby denied.

IT IS THEREFORE, ORDERED, that, based upon all of the above, including all of the pre-filed testimony filed in this proceedings, the pleadings, briefs, letters, exhibits, data request responses and all other documents contained in the record, and all of the oral testimony provided at the hearings in this matter and as found by this Commission as is more fully described in this order, the public convenience and necessity requires and will require the construction, acquisition, operation, maintenance, repair and renewal of the Kemper County IGCC Project to fill the need for additional electric generation previously determined by the Commission in its Phase One Order. It is further,

ORDERED, that the Company's Petition filed in this cause, as conditioned and provided for herein, be, and is hereby, granted. It is further,

ORDERED, that because the Project will provide significant economic benefit to the Kemper County area and the State in general and in order to maximize these benefits, the Commission encourages MPCo to utilize Mississippi labor, resources and services in a prudent and cost effective manner, where ever lawfully possible during the design, procurement and construction of the Project. It is further,

ORDERED, that those prudently incurred pre-construction costs, to the extent allowed under FERC and Commission accounting rules and under generally accepted accounting principles, should be capitalized to the applicable capital work order for the Project. To the extent such costs cannot be capitalized under the applicable accounting rules, we find that such costs should be deferred in a regulatory asset until such costs are authorized to be amortized over a time period to be determined by the Commission.

This Final Order shall be deemed issued on the day it is served upon the parties herein by the Executive Secretary of the Commission who shall note the service date in the file of this Docket.

Chairman Leonard Bentz voted Aye; Vice-Chairman Lynn Posey voted Aye; and Commissioner Brandon Presley voted NO

SO ORDERED by the Commission on this the 24th day of April, 2012.

MISSISSIPPI PUBLIC SERVICE COMMISSION

Leonard Bentz, Chairman

Lynn Posey, Vice-Chairman

Brandon Presley, Commissioner

MISSISSIPPI PUBLIC SERVICE COMMISSION

ATTEST: A True Copy

Brian U. Ray, Executive Secretary

Effective this the 24th day of April, 2012.

EXHIBIT LA-19

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 10
Received: July 18, 2014

SUPPLEMENTAL RESPONSE 9-13-14
SUPPLEMENTAL INFORMATION IN BOLD
CAC 10.2

Request:

For each month in the IGCC 12-13 period, how does the Company determine whether repairs to the Edwardsport IGCC are normal ongoing capital maintenance? Please explain fully, and provide related work orders and accounting documents.

Objection:

Duke Energy Indiana objects to this Request on the grounds that the term "normal ongoing capital maintenance" is vague and ambiguous.

Response:

Subject to and without waiving or limiting its objections, please refer to page 10, line 3 through page 13, line 19 of the Direct Testimony of Diana L. Douglas in IGCC 13. Please also see the Company's response to CAC 10.6.

After discussion with Counsel for CAC, Duke Energy Indiana is providing the following supplemental information: As discussed in the response to CAC 10.6, the Company follows FERC accounting guidance (specifically Electric Plant Instruction 10 from Title 18, Chapter I, Subchapter C, Part 101 of the Code of Federal Regulations) for determining whether the cost of maintenance work should be expensed or capitalized.

In addition and to the extent this Request is seeking information regarding "normal ongoing capital maintenance" under the Settlement Agreement, the Company holds meetings on a regular basis with a cross-functional team (including station, rates, legal, and accounting personnel) where each new capital project established for Edwardsport station is discussed and evaluated in the context of Item 2E of the Settlement Agreement and classified accordingly as an expenditure for ongoing capital maintenance or as an expenditure that should be subject to the Hard Cost Cap. This classification is based upon the circumstances that gave rise to the capital project, not upon specific work orders or accounting documentation. Refer to Confidential Workpapers 9 through 11 filed in IGCC 12 and Confidential Workpapers 9 through 12 filed in IGCC 13 for additional accounting details of the post-in-service ongoing capital projects.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 10
Received: July 18, 2014

CAC 10.6

Request:

For application in the IGCC 12-13 period, did the Company have any written accounting guidance for determining when a repair to a generating plant is capital maintenance?

a) If not, explain fully why not.
b) If so, please provide it.

Objection:

Duke Energy Indiana objects to this Request as vague and ambiguous, particularly the phrases “any written accounting guidance” and “capital maintenance.”

Response:

Subject to and without waiving or limiting its objections, Duke Energy responds as follows: The Company follows FERC accounting guidance (specifically Electric Plant Instruction 10 from Title 18, Chapter I, Subchapter C, Part 101 of the Code of Federal Regulations) for determining whether the cost of maintenance work should be expensed or capitalized. Please also see the Company’s response to CAC 10.3.

EXHIBIT LA-20

DEI-IG
IURC Cause No. 43114 IGCC-12
Data Request Set No. 1
Received: May 12, 2014

SUPPLEMENTAL RESPONSE 12-5-14
SUPPLEMENTAL INFORMATION IN BOLD

DEI-IG 1.8

Request:

Referring to the Settlement Agreement, paragraph 2E and the definition of Construction Costs:

a. Does Duke believe the date of final completion has been achieved?

b. If the answer to the prior question is no, when does Duke believe final completion will be achieved?

c. Please provide the date each of the conditions to substantial completion occurred, items (a) through (f), as reflected on Attachment A to the Settlement Agreement.

d. If any of the conditions to substantial completion have not occurred, items (a) through (f), as reflected on Attachment A to the Settlement Agreement, please provide an explanation of the reasons and the expected date each condition will occur.

e. Please provide the date each of the conditions to final completion occurred, items (a) through (e), as reflected on Attachment A to the Settlement Agreement.

f. If any of the conditions to final completion have not occurred, items (a) through (e), as reflected on Attachment A to the Settlement Agreement, please provide an explanation of the reasons and the expected date each condition will occur.

Response:

a. No.

b. Given that Substantial Completion (as defined by the Duke/GE contract) has not yet occurred, it is difficult to estimate when Final Completion will occur. A more accurate estimate can be provided once the performance testing required for Substantial Completion has occurred. The thermal performance testing is currently scheduled for sometime in the next few weeks. **The performance test and ramping demonstrations are complete with Duke Energy Indiana taking exception to certain adjustments made by GE to the heat rate calculation from the performance test. Duke Energy has reserved its rights and remedies under the Duke Energy/GE Contract, but accepts the performance test as complete because if GE is correct in its adjustments, the heat rate guarantee has been met. There is no dispute about the MW guarantee having been met. The ramp demonstration has been successfully completed. GE and Duke Energy have discussed and agreed upon a Punch List, subject to contractual remedies for any remaining items in dispute. The parties are currently discussing Documentation and a certificate of substantial completion, and anticipate that Substantial Completion will be achieved before the end of 2014. Thereafter, upon completion of the Punch List and further certification, Final Completion will have been achieved. The parties currently anticipate that this will occur in the spring of 2015 as certain Punch List items require a full station outage to be completed.**

c. Of the following:

(a) Delivery of all GEP Equipment shall have occurred;

(b) the performance of the Work shall be complete (other than Work that by its nature cannot be completed until after Substantial Completion (e.g., warranty Work)), with the exception of the Punch List;

(c) the Facility shall have satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees;

(d) the Seller shall have delivered to the Buyer all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract, with the exception of the Punch List;

(e) the Seller shall have provided all training required by Exhibit S, with the exception of the Punch List; and

(f) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.

Only (a) and (e) have occurred. The delivery of major GEP Equipment was completed September 29, 2011 and the training required by Exhibit S was also completed. According to documentation provided by GE, it appears that the final required training was completed by GE on September 26, 2013. Duke and GE continue to work on completion of the additional components of Substantial Completion. **(b) occurred November 12, 2014, upon completion of the ramping demonstration and (c) occurred May 16, 2014.**

d. Please see the response to subpart (b) above. Duke Energy Indiana continues to review the data from the May 2014 performance test and cannot yet state whether the

Facility has satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees. Additionally, until the contractually-required demonstrations have occurred, Duke Energy Indiana and GE could not agree that the "performance of the Work shall be complete" nor could "a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied" be delivered by GE to Duke Energy Indiana. GE is working on compiling the voluminous Documentation required to be delivered to Duke under the contract, but is not yet finished. **Regarding item (d), certain Documentation still remains outstanding. On November 20, 2014, GE delivered a draft certificate of substantial completion to Duke Energy for its review. Duke Energy has not yet completed its review and has not yet signed accepting the certificate. As such, subpart (f) is not complete, but is anticipated to be completed by the end of 2014.**

e. Please see the response to subpart (a) above.

f. Please see the response to subpart (d) above.

EXHIBIT LA-21

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

DEI-IG 4.8

Questions relating to Thompson's testimony in 12:

Request:

See page 3, starting at line 12:

a. What is the status of the ramping and operability demonstration tests?
b. Describe any issues discovered as a result of the ramping and operability demonstration tests.
c. Provide the planned or completed fixes to the issues.
d. Provide the anticipated or known costs of the fixes.
e. Indicate whether Duke is or will seek to recover any of these costs from ratepayers, and if so, explain why such costs are not "being covered by Duke Energy shareholders under the terms of the 2012 Settlement Agreement."

Objection:

Duke Energy Indiana objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding, particularly to the extent it seeks information aboau the operability demonstration tests that have not yet been performed and as such, are outside the scope of this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. The operability demonstration tests have not yet been completed, but are scheduled for August 2014.

b. N/A.

c. N/A.

d. N/A.

e. N/A. Answering further, demonstration of certain facility operability parameters is required under the Contract[1] (it is part of the Work under the Duke Energy/GE Contract, required for Substantial Completion). As such, costs associated with this demonstration are included under the scope (and cost) of the Duke Energy/GE Contract.

[1] See Exhibit T, page 20.

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

DEI-IG 4.9

Questions relating to Thompson's testimony in 12:

Request:

See page 3, starting at line 12:

a. What is the status of the preliminary performance test?
b. Describe any issues discovered as a result of the preliminary performance test.
c. Provide the planned or completed fixes to the issues.
d. Provide the anticipated or known costs of the fixes.
e. Indicate whether Duke is or will seek to recover any of these costs from ratepayers, and if so, explain why such costs are not "being covered by Duke Energy shareholders under the terms of the 2012 Settlement Agreement."

Objection:

Duke Energy Indiana objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding, particularly to the extent it seeks information about the preliminary performance test that was performed on April 2, 2014, and as such, is outside the scope of this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. It was completed April 2, 2014.
b. N/A.
c. N/A.
d. N/A.
e. N/A.

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

DEI-IG 4.10

Questions relating to Thompson's testimony in 12:

Request:

See page 3, starting at line 12:

a. What is the status of the final contractually-required GE performance testing?
b. Describe any issues discovered as a result of the final contractually-required GE performance testing.
c. Provide the planned or completed fixes to the issues.
d. Provide the anticipated or known costs of the fixes.
e. Indicate whether Duke is or will seek to recover any of these costs from ratepayers, and if so, explain why such costs are not "being covered by Duke Energy shareholders under the terms of the 2012 Settlement Agreement."

Objection:

Duke Energy Indiana objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding, particularly to the extent it seeks information about the GE performance testing that was not completed until May 15-16, 2014 and as such, is outside the scope of this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. It was completed May 15-16, 2014.
b. Duke Energy Indiana is still reviewing the data gathered during the performance test to ensure it fully understands GE's findings. That review is not yet completed.
c. N/A.
d. N/A.
e. To the extent there are "issues" uncovered as a result of the GE performance testing that must be resolved in order for GE to reach substantial or final completion (as defined in the 2007 Duke Energy/GE contract), Duke Energy Indiana does not plan to recover the costs to resolve them from its customers.

EXHIBIT LA-22

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

DEI-IG 4.14

Questions relating to Stultz's testimony in 12:

Request:

Referencing Mr. Stultz, pages 4-5, is it correct that as of September 30, 2013:

a. Final unit tuning was not complete.
b. Final unit tuning had to be complete before preliminary testing could be completed.
c. Preliminary testing was not complete.
d. Preliminary testing had to be complete before performance testing could be completed.
e. Performance testing was not complete.
f. Provide the completion date for each of the items in a-e or, if not complete, so indicate.

Objection:

Duke Energy Indiana objects to subparts (a) and (b) as vague and ambiguous, particularly the reference to "final unit tuning." Duke Energy Indiana objects to subpart (f) as already asked and answered.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. See above objection. Answering further, to the extent this Request seeks information about tuning for discrete activities such as the GE contractually-required performance test, yes. However, overall unit tuning is a never ending activity that will continue throughout Edwardsport's life, just as with all generating facilities.

b. See above objection and the Company's response to subpart (a).

c. Yes.

d. Yes. The 2007 Duke Energy/GE Contract specified certain conditions for performance testing, one of which was a preliminary performance test called for under ASME PTC-47.

e. Yes.

f. The preliminary performance testing was performed April 2, 2014, and the performance test was performed May 15-16, 2014.

EXHIBIT LA-23

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 4
Received: July 29, 2014

DEI-IG 4.31

Questions relating to Stultz's testimony in 13:

Request:

Refer to pages 17-19.

a. Please admit that Duke had not accomplished final completion of the Plant as of the time Mr. Stultz filed his testimony in IGCC 13. If Duke denies this, when was final completion accomplished? Explain any denial.
b. Please admit that Duke had not accomplished substantial completion of the Plant as of the time Mr. Stultz filed his testimony in IGCC 13. If Duke denies this, when was final completion accomplished? Explain any denial.
c. Please admit that over a year after declaring the Plant to be in-service, it still had not reached final or substantial completion. Explain any denial.

Objection:

Duke Energy Indiana objects to this request as already asked and answered, as well as discussed in Mr. Stultz's testimony. Duke Energy Indiana also objects to this Request on the grounds that it mischaracterizes the 2007 Duke Energy/GE contract – Duke Energy Indiana does not "accomplish final completion," that is accomplished under the terms of the 2007 Duke Energy/GE contract.

Response:

Subject to and without waiving or limiting its objections and responding with Duke Energy Indiana's understanding of the 2007 Duke Energy/GE Contract and GE's progress towards "final completion" and "substantial completion" of that contract, Duke Energy Indiana responds as follows:

a. Admit.
b. Admit.
c. Admit.

EXHIBIT LA-24

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 3
Received: June 30, 2014

SUPPLEMENTAL RESPONSE 10-13-14
SUPPLEMENTAL INFORMATION IS IN BOLD
DEI-IG 3.6

Request:

Please refer to the IGCC-13 Direct testimony of Mr. Stultz at page 14, lines 12-15.

a. For each month from June 2013 to the present, please provide the percentage of time that Duke Energy dispatch personnel offered Edwardsport on a "must run" basis.

b. For each month from June 2013 to the present, please provide the percentage of time that MISO would not have dispatched Edwardsport *but for* Duke's designation of the plant as "must run."

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant, outside the scope of this proceeding, and not reasonably calculated to lead to admissible evidence in this proceeding. The IGCC-12 and -13 proceeding provides for ongoing review of the Edwardsport Plant during the April 2013 through March 2014 time frame. Any request for documents outside of that time period is both irrelevant and outside the scope of this proceeding. Duke Energy Indiana further objects to this Request on the grounds that it is overbroad and unduly burdensome as the Request seeks an analysis to be performed that has not been performed and to which Duke Energy Indiana objects to performing.

Supplemental Objection (10-13-14):

As noted above, Duke Energy Indiana objects to this request to the extent it seeks a compilation that has not already been performed and which Duke Energy Indiana objects to performing. Furthermore, as explained below, such an analysis would be unduly burdensome.

Supplemental Response (10-13-14):

a. Please see the table below that shows the percent of time, by month, that Edwardsport was offered with a Commit Status of Must Run in the Day-Ahead Market:

Month	
Jun-13	**29%**
Jul-13	**71%**
Aug-13	**100%**
Sep-13	**73%**
Oct-13	**77%**
Nov-13	**43%**
Dec-13	**87%**
Jan-14	**76%**
Feb-14	**20%**
Mar-14	**81%**
Apr-14	**93%**
May-14	**97%**
Jun-14	**97%**
Jul-14	**94%**
Aug-14	**100%**

b. Without waiver of, and subject to the general and specific objections noted above, even attempting to provide such analysis comes with a host of limitations and complications and requires multiple assumptions. There is no way to know whether MISO would have committed Edwardsport, the impact to the station's startup sequence absent commitment, changes to commitment costs and decisions related to de-commitment and re-commitment of the unit, and whether having a new commitment of Edwardsport would have changed Locational Marginal Prices (LMP) for load and energy or Marginal Clearing Prices (MCP) for ancillary services products in the MISO market. In addition, Duke Energy Indiana does not have access to MISO's optimization software that makes these decisions or performs these calculations.

EXHIBIT LA-25

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: June 27, 2014

SUPPLEMENTAL RESPONSE 10-6-14
SUPPLEMENTAL INFORMATION IS IN BOLD
CAC 6.38

Request:

Provide, in electronic spreadsheet readable format, the hourly capacity levels at which Edwardsport has operated when it has been dispatched into MISO.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence in this proceeding. Duke Energy Indiana also objects to this Request as overbroad and unduly burdensome.

Supplemental Response (10-6-14):

In light of the Commission's ruling on the Motion to Compel, Duke Energy Indiana is providing the following supplemental information:

Assuming "hourly capacity levels at which Edwardsport has operated" refers to the amount of net generation produced from the station when producing net generation greater than zero, please see Confidential Attachment CAC 6.38-A, which contains data from April 2013 through March 2014.

CONFIDENTIAL

Confidential Attachment CAC 6.38-A

Electric Production in MWh

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Prepared using the DEI Excel provided on Oct 10 in supplemental response to CAC 6.38

Edwardsport Generation
GenUnit CIN.EDWPORT IGCC

Tab	Column	Month	Days	Year	Maximum Hourly Generation	Sum of MW_Loading	Worse Performance (Lower MWH Generation) After "In Service" than May 2013 Generation (Pre- "in service")
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]			[redacted]	[redacted]	[redacted]
		[redacted]				[redacted]	

Notes and Source
Source: Response to CAC 6.38 CONFIDENTIAL Attachment A Excel file

Pre "In Service" Generation

Tab	Column	Month	Days	Year	Maximum Hourly Generation	Sum of MW_Loading
[redacted]	[redacted]	[redacted]		[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]			[redacted]	[redacted]

COMPARABLE MONTHLY INFORMATION
Edwardsport Actual Net Generation (MWH):
CONFIDENTIAL RESPONSE to DEI-IG 4.24
CONFIDENTIAL RESPONSE to DEI-IG 6.1d

Delivered MWH:
CONFIDENTIAL RESPONSE to DEI-IG 6.1d

[redacted]

[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

[redacted]	
[redacted]	
[redacted]	
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]
[redacted]	[redacted]

EXHIBIT LA-26

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: September 22, 2014

DEI-IG 6.4

Request:

With respect to the GE New Product Introduction ("NPI") testing, please answer the following:

a. Please identify each test.

b. Please identify the date each test was completed.

c. Please identify whether the test needed to be successfully completed in order to ensure full product warranties, contract guarantees, liquidated damage protection, and any other product or contract assurance.

d. Please identify any requirements that needed to be met before the test could be conducted.

e. Please identify whether the Edwardsport IGCC plant needed to be run as a must-run unit in order to conduct the test.

f. Please identify any other limitations in operational performance for the Edwardsport IGCC plant that needed to be implemented prior to completion of the test.

Objection:

Duke Energy Indiana objects to this Request as overbroad and unduly burdensome. Duke further objects to subpart (b) as previously asked and answered. Duke Energy Indiana objects to subpart (d) as not reasonably calculated to lead to admissible evidence in this proceeding. Duke Energy Indiana also objects to subparts (c) through (f) of this Request as vague and ambiguous.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. GE's NPI testing was adjusted over time with certain tests deleted or changed at GE's discretion. Please see the Company's prior confidential response to CAC 10.27, which provides the NPI tests listed in the 2007 Duke/GE contract. Please also see the Direct Testimony of Jack L. Stultz in Cause No. 43114 IGCC-11, Petitioner's Confidential Exhibit A-1, Section 5.b, for what was identified as a listing of NPI tests as of March 31, 2013.

b. Duke Energy Indiana does not maintain the requested information.

c. See above objection. No.

d. See above objection. There were detailed test plans developed by GE and reviewed by the Joint Validation Review Board (a joint Duke/GE group) prior to in-service. To the extent there were requirements prior to those tests, they would presumably have been included in the detailed test plans.

e. See above objection. In the spirit of cooperation, to the extent there was testing that needed to be done at Edwardsport, yes, the plant would be offered to MISO as "must run."

f. See above objection. In the spirit of cooperation, it depends on the test. As examples, some of the tests were to be performed on just one train of the gasifiers, some required two to be operating. Some required the CTs to be co-fired at certain percentages of natural gas and syngas.

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: September 22, 2014

DEI-IG 6.5

Request:

Please list all tests (other than those identified in IG DR 6-4 above) that need to be successfully completed at the Edwardsport IGCC plant in order to ensure full product warranties, contract guarantees, liquidated damage protection, and any other product or contract assurance. For each test identified, please provide the following information:

a. Please identify the date the test or tests were completed. (If the test has not yet been completed, identify the expected date of the test.)

b. Please identify any requirements that needed to be met before the test could be conducted.

c. Please identify whether the Edwardsport IGCC plant needed to be run as a must-run unit in order to conduct the test.

d. Please identify any other limitations in operational performance for the Edwardsport IGCC plant that needed to be implemented prior to completion of the test.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is overbroad and unduly burdensome. Duke Energy Indiana also objects to this Request as vague and ambiguous, particularly the reference to "all tests." Duke Energy Indiana (along with its contractors) ran literally thousands of tests prior to in-service on individual equipment and components.

Response:

Subject to and without waiving or limiting its objections and assuming this Request seeks information about the testing discussed in Exhibit T of the 2007 Duke/GE Contract, Duke Energy Indiana responds as follows:

- On site Performance Test (Section 7.1 Exhibit T)
- On site Emissions Test (Section 7.2 of Exhibit T)
- On site acoustic Test (near field only) (Section 7.3 of Exhibit T)

- Demonstration Tests (Section 6 of Exhibit T)
  - ✓ Flare System Emissions Process Demonstration (T6.1)
  - ✓ Facility Operability Demonstration (6.2)
    - o Facility automatic control ramping
    - o Automatic ramping (1 CT syngas and 1 CT NG)
    - o Automatic Ramping (2 CTs on NG)

a. The tests were performed as follows:

- On Site Performance Test: May 15 and May 16, 2014.
- On site Emissions test: June 12, 2013
- Flare System Emissions Process Demonstration: April 18, 2013
- On site Acoustics test: July 24, 2013

b. Please see Exhibit T of the 2007 Duke/GE Contract.

c. See above objection. In the spirit of cooperation, to the extent there was testing that needed to be done at Edwardsport, yes, the plant would be offered to MISO as “must run.”

d. Please see Exhibit T of the 2007 Duke/GE Contract.

EXHIBIT LA-27

DUKE ENERGY INDIANA, INC.

Allocation Of Rider 61 Revenue Collected From Customers

2009

	January	February	March	April	May	June	July	August	September	October	November	December	Total
Billed 61 Revenue	$ 1,101,128	$ 1,351,032	$ 1,206,180	$ 1,092,560	$ 1,812,692	$ 2,619,532	$ 2,853,677	$ 2,825,882	$ 2,756,028	$ 2,528,973	$ 2,451,808	$ 4,283,696	$ 26,883,188
Less:													
Amount Applicable to Other Items Recoverable/Refundable through Rider 61 [1]	11,220	13,767	12,291	11,133	12,743	12,417	13,526	13,395	13,064	11,987	11,622	85,503	222,668
Amount Related To CWIP	$ 1,089,908	$ 1,337,265	$ 1,193,889	$ 1,081,427	$ 1,799,949	$ 2,607,115	$ 2,840,151	$ 2,812,487	$ 2,742,964	$ 2,516,986	$ 2,440,186	$ 4,198,193	$ 26,660,520

2010

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Prior Periods	Grand Total
Billed 61 Revenue	$ 5,187,241	$ 4,438,872	$ 4,639,284	$ 3,927,392	$ 3,854,569	$ 4,605,643	$ 5,636,000	$ 10,240,161	$ 9,438,686	$ 7,977,667	$ 7,686,404	$ 9,502,446	$ 77,134,365	$ 26,883,188	$ 104,017,553
Less:															
Amount Applicable to Other Items Recoverable/Refundable through Rider 61 [1]	108,984	93,261	97,471	82,515	80,984	96,765	114,411	140,290	129,310	109,294	105,304	130,184	1,288,773	222,668	1,511,441
Amount Related To CWIP	$ 5,078,257	$ 4,345,611	$ 4,541,813	$ 3,844,877	$ 3,773,585	$ 4,508,878	$ 5,521,589	$ 10,099,871	$ 9,309,376	$ 7,868,373	$ 7,581,100	$ 9,372,262	$ 75,845,592	$ 26,660,520	$ 102,506,112

2011

	January	February	March	April	May	June	July	August	September	October	November	December	Total	Prior Periods	Grand Total
Billed 61 Revenue	$ 10,312,643	$ 9,292,273	$ 8,798,386	$ 7,841,395	$ 7,800,166	$ 8,976,052	$ 9,794,794	$ 10,378,050	$ 9,082,132	$ 7,623,860	$ 7,758,163	$ 8,801,428	$ 106,459,342	$ 104,017,553	$ 210,476,895
Less:															
Amount Applicable to Other Items Recoverable/Refundable through Rider 61 [1]	141,283	127,304	120,538	107,427	106,862	122,972	134,189	142,179	124,425	104,447	106,287	120,580	1,458,493	1,511,441	2,969,934
Amount Related To CWIP	$ 10,171,360	$ 9,164,969	$ 8,677,848	$ 7,733,968	$ 7,693,304	$ 8,853,080	$ 9,660,605	$ 10,235,871	$ 8,957,707	$ 7,519,413	$ 7,651,876	$ 8,680,848	$ 105,000,849	$ 102,506,112	$ 207,506,961

2012	January	February	March	April	May	June	July	August	September	October	November	December	Total	Prior Periods	Grand Total
Billed 61 Revenue	$ 9,456,388	$ 8,973,064	$ 8,316,074	$ 7,578,281	$ 7,913,016	$ 8,734,654	$ 10,443,267	$ 9,998,583	$ 8,989,925	$ 7,612,382	$ 7,910,162	$ 8,553,399	$ 104,479,195	$ 210,476,895	$ 314,956,090
Less:															
Amount Applicable to Other Items Recoverable/Refundable through Rider 61 [1]	129,553	122,931	113,930	103,822	108,408	119,665	143,073	136,981	123,162	104,290	108,369	117,182	1,431,366	2,969,934	4,401,300
Amount Related To CWIP	$ 9,326,835	$ 8,850,133	$ 8,202,144	$ 7,474,459	$ 7,804,608	$ 8,614,989	$ 10,300,194	$ 9,861,602	$ 8,866,763	$ 7,508,092	$ 7,801,793	$ 8,436,217	$ 103,047,829	$ 207,506,961	$ 310,554,790

2013	January	February	March	April	May	June	July	August	September	October	November	December	Total	Prior Periods	Grand Total
Billed 61 Revenue	$ 18,432,840	$ 17,327,537	$ 16,732,565	$ 15,828,385	$ 14,501,958	$ 15,911,632	$ 17,504,481	$ 16,997,816	$ 22,796,255				$ 156,033,469	$ 314,956,090	$ 470,989,559
Less:															
Amount Applicable to Other Items Recoverable/Refundable through Rider 61 [1]	(4,625,721)	(4,348,345)	(4,199,037)	(4,139,123)	(3,809,229)	(4,179,508)	(4,597,902)	(4,464,816)	623,022				(33,740,659)	4,401,300	(29,339,359)
Amount Related To CWIP	$ 23,058,561	$ 21,675,882	$ 20,931,602	$ 19,967,508	$ 18,311,187	$ 20,091,140	$ 22,102,383	$ 21,462,632	$ 22,173,233	$ -	$ -	$ -	$ 189,774,128	$ 310,554,790	$ 500,328,918

	Other Items Recoverable/Refundable through Rider 61 [1]	
IGCC 1	January 1, 2009 through May 13, 2009	0.01019
IGCC 2	May 14, 2009 through December 2, 2009	0.00474
IGCC 3	December 3, 2009 through July 28, 2010	0.02101
IGCC 4	July 29, 2010 through December 31, 2012	0.01370
IGCC 8	January 1, 2013 through April 3, 2013	-0.25095
IGCC 9	April 4, 2013 through September 11, 2013	-0.26267
IGCC 10	September 12, 2013 through September 30, 2013	0.19523

[1] Examples are regulatory filing expenses, recoverable operating expenses (O&M, depreciation, property tax, property insurance), Indiana Coal Gasification Technology Investment Tax Credit, credit for depreciation rate reduction, HLF credit, and other items as deemed appropriate.

EXHIBIT LA-28

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 10
Received: July 18, 2014

CAC 10.16

Request:

Did the Training referred to in the response to CAC 6.15 included any written materials?

a) If not, please explain fully why not.
b) If so, please identify and provide the written materials that were used in the Training.

Response:

Yes.

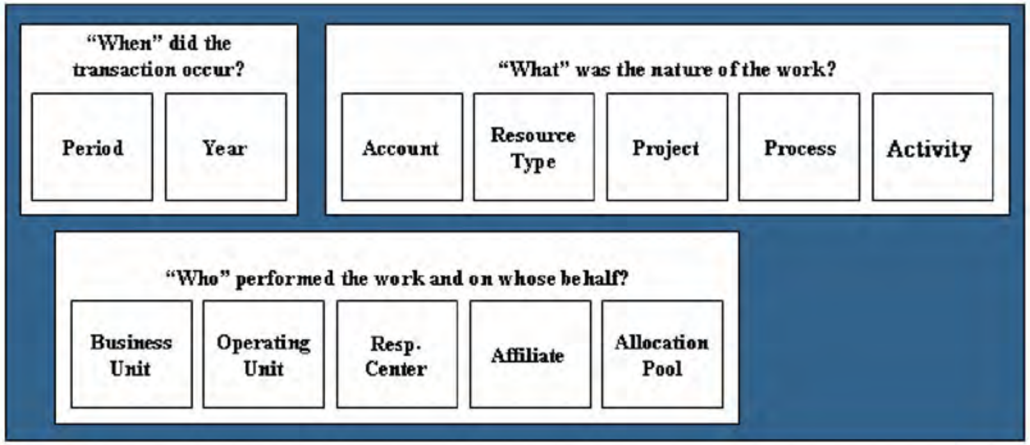
a) N/A
b) Please see Attachment CAC 10.16-A.

DUKE ENERGY®

EDWARDSPORT IGCC O & M ACCOUNTING TRAINING

Bonnie Govert & Steven Dale 2013

Code Block Elements



- Most transactions in the feeder systems will only require entry of:
  - Operating Unit (OU)
  - Responsibility Center
  - Resource Type
  - Process
  - Project (required if capital related; optional for all other transactions)
  - Activity (required if Project is entered)
- All other pieces of the code block will be derived

Minimum Requirements

Code Block Elements - BU

Element	Description	Intended Use
Business Unit	A subset entity of Duke Energy that is independent with regard to one or more operational or accounting functions. Business Unit includes all legal entities plus entities required to support regulatory reporting. A Business Unit has its own balanced set of books	Legal entity reporting
		SEC external reporting
		FERC functional
		Purchase accounting
		Multiple rate structures

Our Business Unit – 75111- DE IN Fossil

Period	Year		Business Unit	Operating Unit	Resp. Center	Affiliate	Allocation Pool		Account	Resource Type	Project	Process	Product		Location

DUKE ENERGY

Code Block – OU & Resp Center

Element	Description	Intended Use	Examples
Operating Unit	A summary organizational view to support management and operational reporting	Units at generating stations	MF07 – Miami Fort Unit 7 100%
		Joint Owner credits	M7DP – Miami Fort Unit 7 DPL Share
		Power Delivery Operations Centers	V493 – Little Miami
		Service Company major function	UTAC – Acctg Svcs Utility
Responsibility Center	The entity that performs work. Responsibility Center supports reporting of costs for a departmental view. Each center is specific to a single Payroll Company	Resource owner (Department w/ budget and staff)	S445 – Power Delivery: Terre Haute Operations S197 – Regulated F/H Fleet: Gibson Station Maintenance RPM2 – Commercial Power: Miami Fort Maintenance S793 – Chief Admin Officer/EBS IT: IT Infrastructure Ops S062 – Chief Financial Officer: DEGS Accounting S608 – Gas Operations: System Engineering

Operating Unit (OU) and Resp Center

DUKE ENERGY

Code Block – OU & Resp. Center

Center Structure for Edwardsport IGCC	
Existing Centers:	
SEGP	Edwardsport IGCC **Construction Center**
SEGS	Edwardsport IGCC Prod. **Service Co. Employees (Pay**
SEGI	Edwardsport IGCC **Production (Union Employees)**
IGCC - Operating Centers: (Pay Corp 529)	
SESM	Edwardsport IGCC **Station Manager**
SEBM	Edwardsport IGCC **Business Manager**
SERM	Edwardsport IGCC **Resource Manager**
SETM	Edwardsport IGCC **Technical Manager**
SEPM	Edwardsport IGCC **Production Manager**
SEST	Edwardsport IGCC **Support Team Mechanical**
SEIE	Edwardsport IGCC **Support Team I & E**
SEMH	Edwardsport IGCC **Material Handling**
SELB	Edwardsport IGCC **Lab**
SECH	Edwardsport IGCC **Waste Water Treatment**
SETR	Edwardsport IGCC **Water Treatment**
SEFG	Edwardsport IGCC **Facilities/Grounds**
SEEN	Edwardsport IGCC **Environmental**

Current Edwardsport IGCC OU set up			
MFG OUG - Manufacturing			
ED01	Edwardsport IGCC	75111	DE Indiana Fossil
ED02	Edwardsport IGCC Steam Turbine	75111	DE Indiana Fossil
ED03	Edwardsport IGCC CT1	75111	DE Indiana Fossil
ED04	Edwardsport IGCC CT2	75111	DE Indiana Fossil
GA OUG -General Administrative			
EDGA	Edwardsport IGCC GA OU	75111	DE Indiana Fossil

Operating Unit (OU) and Resp Center

DUKE ENERGY

Code Block – Resource Type

Element	Description	Intended Use	Examples
Resource Type	The category of costs that describe the products, services or resources used to perform tasks or activities	Direct Labor	11000 - Labor
		Union-specific labor	11002 - Labor-Union
		Allocations	18000 - Labor Overhead Allocations
		Benefits	1B210 - Medical Active
		Material	21000 - Direct Material/Inventory Cost
		Employee Expense	40000 - Travel Expenses (Non Meals)
		Tax	41000 - Meals and Entertainment (50%)
		Outside Services	69000 - Consultant
		Insurance	71000 - Property Insurance

Resource Type

DUKE ENERGY

Code Block - Account

Element	Description	Intended Use	Examples
Account	This category shows what FERC account the charge belongs to.	O & M Accounts – Coal - Operations	500000-507000
		O & M Accounts – Coal - Maintenance	510000-515000
		O & M Accounts – CT's	546000-554000
		Capital - Install	107000
		Capital - Retirement	108620
		Engineering Study	183000
		Inventory	154100

Accounts

Code Block - Process

Element	Description	Intended Use	Examples
Process	Ongoing or operational work activities	Expenditures by activity	MNTEL - Corrective Mnt. On Electrical PVMET - Inspect Equipment & Tools ROSUPGN - Refueling Site Support NLDSHPM - Prev Mnt Lead Shielding NR Inn

Process: A set of unique Fossil/Hydro work activities that will derive the Account depending upon the type of work. Processes are grouped into the following:

- **Base** – Yearly routine costs to operate the plant, includes cost in both Operations and Maintenance accounts.
- **Non Base** – Discretionary costs that are not required to operate the plant and does not require a planned outage to complete. (i.e. work done every 3-5 years)
- **Planned Outage** – All work done when a unit is off-line (planned outages includes yearly maintenance outages and major equipment outages)
- **Forced Outage** – Work being done in response to an unplanned unit event that causes the unit to be unavailable.

Process

DUKE ENERGY®

Code Block - Process

B / F / N / P	HAL System			HAL Sub-System			Process	Long Description	Short Desc	Account Model ID AM	Account ID AM	HAL SUB_SYSTEM	HAL Sys_Contents
B	B	L	R	B	U	D	BBLRBUD	Boiler Budget Only	BBLRBUD	51210	0512100		
B	B	L	R	A	U	X	BBLRAUX	BOILER, AUX -Base	BBLRAUX	51210	0512100	BOILER, AUX	Aux Boilers incl HVAC use
F	B	L	R	A	U	X	FBLRAUX	BOILER, AUX - FOut	FBLRAUX	51210	0512100		
N	B	L	R	A	U	X	NBLRAUX	BOILER AUX - NBase	NBLRAUX	51210	0512100		
P	B	L	R	A	U	X	PBLRAUX	BOILER AUX - POut	PBLRAUX	51210	0512100		
F	B	L	R	B	R	N	FBLRBRN	FUEL PRIM BURNING EQUIP -FOut	FBLRBRN	51210	0512100	FUEL PRIMARY BURNING EQUIP	Primary Fuel Burning Equip
N	B	L	R	B	R	N	NBLRBRN	FUEL PRIMARY BURNING EQUIP - NBase	NBLRBRN	51210	0512100		
P	B	L	R	B	R	N	PBLRBRN	FUEL PRIMARY BURNING EQUIP - POut	PBLRBRN	51210	0512100		
B	B	L	R	B	R	N	BBLRBRN	FUEL PRIMARY BURNING EQUIP -Base	BBLRBRN	51210	0512100		

Non-Equipment Based Process Values - will begin with a "B"

B	A	D	M			BADM	Administrative Services	BADM	50000	0500000	
B	A	D	V			BADV	ADVERTISING	BADV	50600	0506000	
B	F	L	D			BFLD	Fix Labor Distrib Default Base	BFLD	50000	0500000	
B	B	G	M	C	L	BBGMCL	Plant Cleaning	BBGMCL	50600	0506000	corrected acct# 12-9-2010
B	B	G	M	G	K	BBGMGK	Groundskeeping	BBGMGK	50600	0506000	corrected acct# 12-9-2010
B	B	G	M	S	E	BBGMSE	Plant Security	BBGMSE	50600	0506000	
B	I	T	S	U	P	BITSUP	IT SUPPORT	BITSUP	50600	0506000	
B	L	M	O	R	P	BLMORP	Recreation Planning	BLMORP	50600	0506000	
B	U	S	G	S		BUSGS	USGS Gages Base	BUSGS	50600	0506000	

Process – Hal Codes

Code Block - Project

Element	Description	Intended Use	Examples
Project	A set of related activities that has a definite start and stop date, where the operational or financial groups have identified a need to track costs during the life of the project Projects can be broken out into multiple smaller scopes of work through an Activity Project/Activity combinations are used to derive Accounts Activities can be broken out to provide separation of work tasks with different accounting (e.g., installations versus removals)	Capital Projects	Project Example - B3174 – WHZ-Repl BA Settling Tnk Liner Activity Example - Install – Installation of tank liner (107)
		O&M projects	Project Example - B3174 – WHZ-Repl BA Settling Tnk Liner Activity Example - Expense – O&M expenses

Project – MUST have an activity

Capital Projects

2013
IGCC

Capital
Projects

- Misc. Valves
- General Equipment
- Structures and Platforms
- Combustion Inspection on CT2
- Unidentified Capital Projects
- Any work identified as Closeout work will be charged to the Major Capital Project. David Whitman will manage these line items and he will have work orders set up on Closeout accounting for this work.

DUKE ENERGY®

Effected Systems - Emax

Systems Effected:
E-Max
PR's & POs
Labor
Expenses
Tax – OUs
CTRs

- Emax locations and assets are built with O & M accounting on them. Work Orders that you write will automatically have the correct GL string.
- If you are ordering material, use the **PR function** from the work order so that your accounting will align with your work order.
- O & M and Capital projects have to be manually added to your GL string – this function will be done by a planner. You will need to email them your WO number and have them add the project.
- The account will need to be modified for a capital project.

Effected System – PRs and POs

Systems Effected:
E-Max
PR's & POs
Labor
Expenses
Tax – OUs
CTRs

- If you are writing a stand alone PR for your PO, you need to be sure you have all the correct accounting components on your Purchase Request. Always reference a work order if you have one for the PO you are writing.
- O & M projects (Non-base and Outage) have to be manually added to your accounting string.

Effected Systems - Labor

Systems Effected:
E-Max
PR's & POs
Labor
Expenses
Tax – OUs
CTRs

- My Time default labor for all exempt employees will be updated by the Administration staff with O & M accounting.
- Timesheet templates will be sent out to exempt employees with the O & M accounting on them. This will be used for Overtime (O & M). Non productive time such as vacation, sick, etc. will be reported as it is today. Work done on capital projects and Closeout items will need to be reported using the work order for that work.

DUKE ENERGY®

Effected Systems - Expenses

Systems Effected:
E-Max
PR's & POs
Labor
Expenses
Tax – OUs
CTRs

- Default accounting will need to be updated in the expense system when we go commercial. Your new default accounting will be O & M and you will use a work order for any capital or closeout expenses you may have.
- You have to be entering an expense report for it to take new accounting defaults.
- Expenses could go to a general admin type process, training, maint process, project (O & M or capital), etc.

DUKE ENERGY

Effected Systems – Tax OUs

Systems Effected:
E-Max
PR's & POs
Labor
Expenses
Tax – OUs
CTRs

- We had a class here about18 months ago that covered the manufacturing area of the plant. Manufacturing starts at the reclaim belt and ends at the step up transformer. The manufacturing area of the plant is not taxable. Parts outside of this area are considered General and Administrative and are taxable. The OU EDGA must be used on these taxable items.
- Capital or O & M Projects that are for a specific unit must be used with a specific OU such as ED03 for CT #1.

Effected Systems – CTRs

Systems Effected:
- E-Max
- PR's & POs
- Labor
- Expenses
- Tax – OUs
- CTRs

- Contractor Time Reporting (CTR) is used for our base contractors. Timesheets for these contractors are entered into eMax by the Administrative staff. Invoices from these contractors are then reconciled via excel from the timesheet entry. The excel spreadsheet can then be uploaded into eMax which allows this time to be recorded to the Work Order. Contractors are paid from this reconciled upload and do not send invoices to AP.
- It is essential that WO have the correct accounting and projects on them so that this CTR process is reported correctly.

EXHIBIT LA-29

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CAC 18.28

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

During the IGCC 12 and 13 review periods, did the Company have any other WorkOrders or Funding Requests for Edwardsport capital expenditures or O&M expenditures besides those that were provided in the response to CAC 10.2?

a) If not, explain fully why not.
b) If so, identify and provide the other WorkOrders or Funding Requests for Edwardsport capital expenditures or O&M expenditures that have been claimed by the Company in its IGCC 12 and IGCC 13 applications.

Response:

No.

a) There were no other "WorkOrders or Funding Requests" for Edwardsport capital expenditures that have been included for recovery by the Company in this proceeding. The Company does not use the referenced "WorkOrders or Funding Requests" for O&M expenditures.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CAC 18.29

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Does the Company have any Work Orders or Funding Requests for any Edwardsport O&M expenses claimed by the Company in the Company's IGCC 12 or IGCC 13 applications?

a) If not, explain fully why not.
b) If so, identify and provide all Work Orders or Funding Requests for Edwardsport O&M expenses that affected costs claimed by the Company in its IGCC 12 and 13 applications.

Response:

Please see the Company's response to CAC 18.28.

EXHIBIT LA-30

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 22
Received: November 6, 2014

CAC 22.3

Request:

Please provide copies of each of the WOs and/or SWPs issued with the numbers listed below according to the following detailed Shift Report forms:

a. Gasification, Night Shift, June 27, 2014, #5771071
b. Gasification, Night Shift, June 27, 2014, #5770998
c. Gasification, Night Shift, June 26, 2014, #5765460
d. Gasification, Night Shift, June 26, 2014, #5732663
e. Gasification, Day Shift, June 20, 2014, #5726015
f. Gasification, Day Shift, June 17, 2014, #5707486
g. Gasification, Day Shift, June 15, 2014, #5692087
h. Gasification, Day Shift, June 11, 2014, #5669303
i. Gasification, Night Shift, June 11, 2014, #5675823
j. Gasification, Day Shift, June 8, 2014, #5653300
k. Gasification, Day Shift, June 8, 2014, #5653298
l. Gasification, Night Shift, June 5, 2014, #5640202
m. Gasification, Day Shift, June 4, 2014, #5630898
n. Gasification, Day Shift, June 4, 2014, #5630414
o. Gasification, Day Shift, May 20, 2014, #5546713
p. Gasification, Day Shift, May 15, 2014, #5519385
q. Gasification, Day Shift, May 5, 2014, #5452235
r. Gasification, Day Shift, February 28, 2014, #4936679
s. Power-BOP, Day Shift, February 28, 2014, #5068471
t. Power-BOP, Day Shift, February 28, 2014, #5057492
u. Power-BOP, Day Shift, February 28, 2014, #5057430
v. Power-BOP, Day Shift, February 28, 2014, #5030396
w. Power-BOP, Day Shift, February 28, 2014, #5024342
x. Power-BOP, Day Shift, February 28, 2014, #4974019
y. Power-BOP, Day Shift, February 28, 2014, #4794368
z. Power-BOP, Day Shift, February 28, 2014, #5060040
aa. Power-BOP, Day Shift, February 28, 2014, #4955914
bb. Power-BOP, Day Shift, February 28, 2014, #5066130
cc. Gasification, Day Shift, December 29, 2013, #4717977
dd. Gasification, Day Shift, December 29, 2013, #4705981

ee. Gasification, Day Shift, December 29, 2013, #4705934
ff. Power-BOP, Day Shift, December 29, 2013, #4718630
gg. Power-BOP, Day Shift, December 29, 2013, #4717828
hh. Power-BOP, Day Shift, December 29, 2013, #4717327
ii. Power-BOP, Day Shift, December 29, 2013, #4715381
jj. Power-BOP, Day Shift, December 29, 2013, #4713763
kk. Power-BOP, Day Shift, December 29, 2013, #4707877
ll. Power-BOP, Day Shift, December 29, 2013, #4699934
mm. Power-BOP, Day Shift, December 29, 2013, #4669366
nn. Power-BOP, Day Shift, December 29, 2013, #4668572

Objection:

Duke Energy Indiana objects to this Request as overbroad and unduly burdensome. Duke Energy Indiana also objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding, particularly to the extent it seeks work orders generated after March 31, 2014, which would be outside the scope of this proceeding.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: Please see Confidential Attachment CAC 22.3-A.

[redacted]

EXHIBIT LA-31

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 22
Received: November 6, 2014

CAC 22.4

Request:

For each WO and/or SWP listed in JIs' Data Request 22.3:

a. Provide the associated journal entries/pages of recorded costs.
b. State whether the recorded costs were classified as Construction or Operating Costs and, if Operating Costs, whether they were Expensed or Capitalized.
c. Identify by name and position title the individual who classified the recorded costs associated with each WO and/or SWP.
d. Identify or state the criteria by which the recorded costs associated with each WO and/or SWP were classified as Construction or Operating Costs and, if Operating Costs, whether they were Expensed or Capitalized.
e. Identify the specific Duke witness Douglas IGCC Exhibit and/or Workpaper and related line item(s) in which the recorded costs associated with each WO and/or SWP has been or will be included for IGCC cost reporting and rate recovery purposes.
f. State whether each WO and/or SWP was reviewed by the special committee identified and described by the Company in response to CAC DR-17. If not, please explain why not. If so, please state at which meeting of the special committee each such WO and/or SWP was reviewed and explain the reason(s) the committee classified the WO and/or SWP in the category that it did.

Objection:

Duke Energy Indiana objects to this Request as not reasonably calculated to lead to admissible evidence in this proceeding particularly to the extent it seeks information regarding work orders generated after March 31, 2014. Duke Energy Indiana also objects to this Request as overbroad and unduly burdensome. Duke Energy Indiana also objects to subpart (f) of this Request to the extent it seeks attorney-client privileged communications and attorney work product.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Please see Confidential Attachment CAC 22.4-A for costs which were recorded during the IGCC 13 period for the referenced Maximo work order numbers that were written during the IGCC 13 period. Please note that there were no costs during this period for eleven of the referenced work order numbers. This can occur for a variety of reasons, including, but not limited to, the following: (1) work pursuant to a work order has not yet been scheduled or completed; (2) it is determined upon review of the work order that no work is necessary; or (3) duplicate work orders are entered in the system.
b. The costs were classified as operating costs, which were expensed.
c. See above objection.
d. The Company follows FERC accounting guidance (specifically Electric Plant Instruction 3 from Title 18, Chapter I, Subchapter C, Part 101 of the Code of Federal Regulations) for determining whether the cost of operation or maintenance work should be expensed or capitalized. Additionally, in order to be expensed, operating costs at the IGCC plant must be incurred on or after June 7, 2013, and not qualify as part of "Construction Costs" as defined in the Settlement Agreement approved in Cause No. 43114 IGCC 4S1 (specifically Term 2 and as described in subpart E).
e. The costs would have been included in the amounts shown on Petitioner's Confidential Exhibit B-2, Page 8 of 12, in IGCC 13 on line 19 (for the line items denoted with a "Baseload Contract Labor" Resource Type Long Description on Confidential Attachment CAC 22.4-A) and on line 20 (for the line items denoted with a "Direct Material/Inventory Cost," "Direct Material Purchases," or "Salvage" Resource Type Long Description on Confidential Attachment CAC 22.4-A.) The costs would also have been included in the amounts shown on the respective lines for each Resource Type in the "All Other" section of Workpaper 10A filed in IGCC 13 and on the respective lines for the account numbers listed on Confidential Attachment CAC 22.4-A in Workpaper 10B filed in IGCC 13.
f. No. Their primary use being maintenance and safety management, Maximo work orders or safe work permits are not reviewed by the referenced committee.

Confidential Attachment CAC 22.4-A

[redacted]

EXHIBIT LA-32

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 25
Received: November 26, 2014

CAC 25.2

Request:

Please reference the Company's Responses to JIs' DR 22.2 and 22.3, including Confidential Attachment 22.3-A.

a. Please provide a complete index in the same format as Confidential Attachment 22.3-A for all Works Orders and Safe Work Permits for Edwardsport issued between June 7, 2013 and March 31, 2014 which were entered in Maximo.
b. Please provide a complete index (or set of indices) in a comparable format to Confidential Attachment 22.3-A for the Work Orders and Safe Work Permits for Edwardsport issued between June 7, 2013 and March 31, 2013 which were NOT entered in Maximo.
c. Please identify by name or other distinctive identifier the system(s) analogous to Maximo in which the Work Orders and Safe Work Permits identified in response to DR-25.2(b) are indexed.
d. Please state whether any of the Work Orders and Safe Work Permits identified in response to DR-25.2(c) were reviewed by the special committee described in the DEI Responses to JIs DR-17. If not, please explain why not.
e. For each Work Order and Safe Work Permit included in the indices provided in response to DR-25.2(a) and (b), please provide the associated costs proposed for recovery in (1) IGCC-12, and (2) IGCC-13.

Objection:

Duke Energy Indiana objects to subparts (b) and (c) as vague and ambiguous. Duke Energy Indiana also objects to subpart (e) as unduly burdensome.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. Please see Confidential Attachment CAC 25.2-A. Regarding the portion of the request seeking an index of Safe Work Permits, please see the Company's prior response to CAC 22.2 in which Duke Energy Indiana explained that it does not maintain a list of safe work permits.

b. N/A

c. N/A

d. N/A

e. Please see Confidential Attachment CAC 25.2-B.

EXHIBIT LA-33

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.8

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011201. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.9

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011202. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.10

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011220. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.11

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011247. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.12

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011248. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.13

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011249. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.14

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011320. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.15

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011231. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.16

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011322. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.17

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011323. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.18

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011327. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.19

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011329. Is the cost of this work order, which is estimated by DEI to be $[redacted] after removal and $[redacted] before removal being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.
c) What is the negative removal amount based upon?

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A
c) It is based on an estimate of salvage value.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.20

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011330. Is the cost of this work order, which is estimated by DEI to be $[redacted] after removal and $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.

b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

c) What is the negative removal amount based upon?

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A
c) It is based on an estimate of salvage value.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.21

<u>Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:</u>

Request:

Refer to Project Number ED011332. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.22

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011333. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.23

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011334. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.24

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011335. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.25

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011336. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company's prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CONFIDENTIAL
CAC 18.26

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Refer to Project Number ED011337. Is the cost of this work order, which is estimated by DEI to be $[redacted] being treated by DEI as being subject to the hard cost cap?

a) If not, explain fully why not.
b) If so, provide the analysis by DEI that resulted in this work order's cost being treated by DEI as being subject to the hard cost cap.

Objection:

Duke Energy Indiana objects to this Request as previously asked and answered. Duke Energy Indiana also objects to this Request to the extent it requires documentation or compilation which has not been prepared and to which Duke Energy Indiana objects preparing. Duke Energy Indiana further objects to this Request to the extent it is seeking attorney-client privileged communications and attorney work project.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana replies as follows:

No.

a) Because the project is not part of Construction Costs subject to the Hard Cost Cap as defined in Section 2.E of the Settlement Agreement in Cause No. 43114 IGCC 4S1. Answering further, please see the Company’s prior response to CAC 17.2 for the criteria the Company used to make this determination.
b) N/A

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 18
Received: October 21, 2014

CAC 18.27

Refer to the Work Orders that were provided in the Confidential Attachment to CAC 10.2:

Request:

Please confirm that the Company's response to CAC 10.2 does not include any WorkOrders or Funding Requests for Edwardsport O&M expenses. If this cannot be confirmed, provide a complete explanation.

Response:

The Company's response to CAC 10.2 "does not include any WorkOrders or Funding Requests for Edwardsport O&M expenses."

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF DUKE ENERGY INDIANA, INC. SEEKING (1) APPROVAL OF AN ONGOING REVIEW PROGRESS REPORT PURSUANT TO IND. CODE 8-1-8.5 AND 8-1-8.7; AND (2) AUTHORITY TO REFLECT COSTS INCURRED FOR THE EDWARDSPORT INTEGRATED GASIFICATION COMBINED CYCLE GENERATING FACILITY ("IGCC PROJECT") PROPERTY UNDER CONSTRUCTION IN ITS RATES AND AUTHORITY TO RECOVER APPUCABLE RELATED COSTS AND CREDITS THROUGH ITS INTEGRATED COAL GASIFICATION COMBINED CYCLE GENERATING FACILITY COST RECOVERY ADJUSTMENT, STANDARD CONTRACT RIDER NO. 61 PURSUANT TO IND. CODE §§ 8-1-8.8-11 AND-12	)	**CAUSE NO. 43114 IGCC-12 & 13**

DIRECT TESTIMONY OF DAVID A. SCHLISSEL
ON BEHALF OF
JOINT INTERVENORS
DECEMBER 15, 2014

PUBLIC VERSION—CONFIDENTIAL INFORMATION REDACTED

INTRODUCTION

Q. Please state your name and business address.

A. My name is David A. Schlissel. I am the President of Schlissel Technical Consulting, Inc., 45 Horace Road, Belmont, MA 02478.

Q. On whose behalf are you testifying?

A. I am testifying on behalf of the Citizens Action Coalition of Indiana, Valley Watch, Save the Valley and the Sierra Club. ("Joint Intervenors")

Q. Please summarize your educational background and recent work experience.

A. I graduated from the Massachusetts Institute of Technology in 1968 with a Bachelor of Science Degree in Engineering. In 1969, I received a Master of Science Degree in Engineering from Stanford University. In 1973, I received a Law Degree from Stanford University. In addition, I studied nuclear engineering at the Massachusetts Institute of Technology during the years 1983-1986.

Since 1983 I have been retained by governmental bodies, publicly-owned utilities, and private organizations in 38 states to prepare expert testimony and analyses on engineering and economic issues related to electric utilities. My recent clients have included the U.S. Department of Justice, the Attorney General and the Governor of the State of New York, state consumer advocates, and national and local environmental and consumer organizations.

I have filed expert testimony before state regulatory commissions in Arkansas, Arizona, California, Colorado, Connecticut, Florida, Georgia, Illinois, Indiana, Iowa, Kansas, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, North Carolina, North Dakota, Ohio, Oregon, Rhode Island, South Carolina, South Dakota, Texas, Vermont, Virginia, West Virginia, and Wisconsin and before an Atomic Safety & Licensing Board of the U.S. Nuclear Regulatory Commission.

A copy of my current resume is included as Exhibit DAS-1. Additional information about my work is available at www.schlissel-technical.com.

Q. Have you testified previously before this Commission?

A. Yes. I have testified in Causes Nos. 38045, 43114, 43114 S1, and 43114 IGCC-1, IGCC-4, IGCC-4S1, IGCC-8 and IGCC-10. I also submitted testimony in Cause 38702-FAC-40-S1 which was settled prior to the scheduled hearings.

Q. Have you previously submitted testimony in Cause No. 43114 IGCC-12?

A. Yes.

Q. Are you withdrawing that testimony?

A. Yes. I am withdrawing that testimony and will address the same issues in this testimony.

Q. What is the purpose of your testimony in this proceeding?

A. I have been requested by Joint Intervenors to assess (1) whether the Edwardsport Integrated Gasification Combined Cycle ("Edwardsport" or "IGCC") was in service between June 7, 2013 and the March 31, 2014 end of the IGCC-13 review period and (2) the current status and future prospects of the Edwardsport Project, with a particular emphasis on the plant's operating performance, technical problems and related costs which pose significant risks to ratepayers notwithstanding the Settlement approved by the Commission, with certain modifications, in Cause No. 43114-IGCC-4S1.

Q. What materials have you reviewed in your preparation of this testimony?

A. I have reviewed the testimony and exhibits of the Duke Energy Indiana's ("Duke," "DEI" or "the Company") witnesses in IGCC-12 and IGCC-13 and the Company's responses to discovery requests submitted by Joint Intervenors and the other active parties to those proceedings, as well as the testimony and discovery responses filed by Duke in Causes Nos. 38707-FAC-99 through FAC-102.

SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your principal conclusions and findings.

A. My principal conclusions are as follows:

1. The Company's declaration that Edwardsport was "in-service" on June 7, 2013 was an obvious attempt to circumvent or evade the construction cost cap proposed in the IGCC-4S1 Settlement and adopted by the IURC in its final order of December 27, 2012 as the plant was not "in service" in any meaningful way between June 7, 2013 and the March 31, 2014 end of the IGCC-12 and IGCC-13 review periods.

2. By any reasonable measure such as availability on syngas, average power output, capacity factor and heat rate, Edwardsport's operating performance during the period June 7, 2013 through March 31, 2014 was extremely poor and unreliable and was significantly worse than the Company had claimed it would be in IGCC-4S1.

   More specifically:

   (a) Edwardsport's availability on syngas was only 35 percent, far below the 75 percent availability on syngas that Duke had promised for the plant's first 15 months of operation.

   (b) Edwardsport's actual capacity factor on syngas was only 21 percent, far below the 72 percent capacity factor that the Company had forecast for the plant's first year of operation. Its actual capacity factor on both syngas and natural gas was only 31 percent.

   (c) Edwardsport's actual generation was less than one-half of what Duke had forecast for the period June 2013 through March 31, 2014 at the end of December 2012, a mere six months before the plant was declared to be in-service.

(d) Edwardsport generated 586 MW net, its summer month net capacity rating, for only a single hour during the summer months of the IGCC-12 and IGCC-13 review periods, and that was on August 9, 2013. Edwardsport has never generated at its 618 MW net non-summer month capacity rating at any time during the IGCC-12 and IGCC-13 review periods.

(e) Edwardsport's actual monthly heat rates were much higher (that is, worse) than the 9313 BTU/KWh heat rate at which the Company told the IURC the plant would operate.

(f) Edwardsport had a dramatically higher Equivalent Forced Outage Rate than the relevant industry comparison group.

3. This extremely poor performance demonstrated that Edwardsport was not in commercial operation as an integrated gasification combined cycle (IGCC) base load power plant with a rated capacity of 618 megawatts (MW) for the months of October through May and 586 MW for the months of June through September or ready for commercial operation, either on June 7, 2013 or at any time during the IGCC-12 and IGCC-13 review periods.

4. It is unambiguous that in 2011, Duke told the Commission that it intended Edwardsport to be "in-service" when the full capacity of the plant operating as an IGCC plant was economically dispatchable by MISO. However, the plant was neither available at full load nor economically dispatchable by MISO when it was declared "in-service" by Duke on June 7, 2013. More than a year later, Edwardsport still has not met this criterion the Company gave the Commission in IGCC-4S1.

5. As the plant's construction cost rose and its schedule became extended, Duke decided to declare Edwardsport "in-service" prior to the date when Edwardsport had achieved the "substantial completion" milestone in its contract with General Electric. Instead, the Company decided that it would declare Edwardsport to be "in-service" after both gasifiers had run in parallel for five days or 120 hours of non-consecutive operation. However, Duke actually declared the plant "in-service" on June 7, 2013, after the gasifiers had only run in parallel for 53 hours.

6. Duke only offered Edwardsport for economic dispatch by MISO for a very limited number of hours during the IGCC-12 and IGCC-13 review periods when it was operating on natural gas. Instead, during the remaining hours of the review periods, including all of the hours when the plant was operating on syngas, it was "self-scheduled" by Duke as a "must run" unit during those periods and its output has been classified as test generation.

7. There was only one instance in March 2014 when MISO called upon Edwardsport to operate. However, Duke declined to start the plant at that time.

8. Edwardsport was still being self-scheduled by Duke as "must run" as of the mid-September start of Edwardsport's Fall 2014 outage. Duke has said that it would no longer designate Edwardsport as "must run" by MISO only at the conclusion of the fall 2014 outage, which occurred in the first half of October, 16 months after it declared the plant to be "in-service." However, it is unclear whether this has actually happened.

9. In IGCC-8 in 2012, the Company said that Edwardsport would be declared "in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility." However, Edwardsport had not completed all necessary startup and preoperational testing as of

June 7, 2013, the date when it was declared to be "in-service," or as of March 31, 2014, further demonstrating that the plant was not in commercial operation or ready for commercial operation at any point in the IGCC-12 and the IGCC-13 review periods.

10. The gasification portion of Edwardsport cannot be considered to have been "in-service" during the period June 7, 2013 through March 31, 2014 given the incomplete status of testing, the ongoing technical issues and equipment problems, and poor availability. Without both trains of its gasification plant operating as intended in tandem with both its combustion turbines and its steam turbine to produce electricity economically dispatched by MISO, Edwardsport as a whole cannot be considered to be "in-service" as an **Integrated** Gasification Combined Cycle power plant.

11. The Company originally projected low CO_2 emissions from Edwardsport even without the carbon capture and sequestration. However, Edwardsport's CO_2 emissions during 2013 after it was declared "in service" and the first nine months of 2014 were substantially higher than Duke projected in the IGCC-4S1 proceedings.

Q. Please summarize your recommendations.

A. I am recommending that the IURC:

1. Find that Edwardsport was not "in-service" as that term was defined in the IGCC-4S1 Settlement at any time during the period June 7, 2013 through March 31, 2014.

2. Adopt a performance standard that requires that the Company, not ratepayers, bear all costs resulting from the plant's failure to achieve a 72 percent capacity factor while burning syngas during Edwardsport's first 15 months of commercial operation.

3. Adopt a performance standard that requires that the Company, not ratepayers, bear all costs resulting from the plant's failure to achieve an 82 percent capacity factor while burning syngas during each twelve-month period following the end of Edwardsport's first 15 months of commercial operation.

4. Adopt a performance standard that requires that the Company, not ratepayers, bear all costs resulting from the plant's failure to achieve and maintain on an ongoing basis during its commercial operation the CO_2 emissions rate projected during its CPCN proceedings.

Q. In the testimony which you earlier pre-filed on April 2, 2014 in Cause No. 43114 IGCC-12 but have now withdrawn and replaced with this testimony in consolidated Cause Nos. 43114-IGCC-12 & 13, you recommended that the Commission initiate a special investigation of Edwardsport and/or a general rate case for Duke Energy Indiana. Do you renew that recommendation in this testimony?

A. I am advised by counsel for Joint Intervenors that it remains my clients' legal position that Edwardsport should be determined by the Commission in a general rate case for Duke Energy Indiana to be "used and useful" within the meaning of Ind. Code § 8-1-2-6 prior to authorizing the recovery through rates under Ind. Code § 8-1-8.8-1 *et seq*. of the post in-service operating costs of Edwardsport, notwithstanding the Commission's ruling to the contrary in its Docket Entry of June 10, 2014. It also remains my professional opinion that sound regulatory policy requires that the post in-service operating costs of a baseload generating plant of the size and cost of Edwardsport be authorized for recovery through customer rates only after the Commission has determined the plant to be both "in service" and "reasonably necessary for the provision of utility service" in a general rate case for the utility which owns 100% of the plant. So, this testimony of mine should not be construed to withdraw, abandon or waive those positions for purposes of any subsequent appeal which my clients may take of a

Commission final order in this consolidated Cause premised on the June 10, 2014 Docket Entry.

However, my testimony does not rely on the legal and policy positions earlier taken by my clients and me regarding the necessity for a "used and useful" determination within the meaning of Ind. Code § 8-1-2-6 by the Commission in a general rate case. Instead, my testimony relies on the overwhelming evidence that Edwardsport has not been in "commercial operation" or ready for commercial operation but instead has been in "testing" for the entire period of June 7, 2013 through March 31, 2014 and thus none of its costs during that period may properly be characterized as "reasonable and necessary" operating costs within the meaning of Ind. Code § 8-1-8.8-1 *et seq*. Instead, they should be characterized as construction costs subject to the "cost cap" approved by the Commission in Cause No. 43114-IGGC-4S1. Alternatively, should the Commission conclude that Edwardsport has been in "commercial operation" or ready for commercial operation for some or all of the period between June 7, 2013 and March 31, 2014, my testimony is based on the overwhelming evidence that the costs during that period have been excessive in significant part and thus not "reasonable and necessary" within the meaning of Ind. Code § 8-1-8.8-1 *et seq*.

As a result, my recommendation in this consolidated cause is that the costs incurred for Edwardsport from June 7, 2013 through March 31, 2014 should be disallowed, in whole or in significant part, for purposes of recovery from customers through Rider 61 without the need for a Duke Energy Indiana general rate case or a further special investigation of Edwardsport.

EDWARDSPORT OPERATIONS DURING THE PERIOD JUNE 2013 THROUGH MARCH 2014.

Q. Do you agree with Duke witness Stultz that availability is a better measure of a generating facility's performance than its capacity factor?[1]

A. No. A power plant's availability only measures the number of hours it is able to provide electricity to the grid during a certain period (e.g., monthly or yearly), divided by the total number of hours in that period. It does not measure the level of generation actually provided by the plant during that period.

For example, when calculating the availability factor, an hour in which a large generating facility like Edwardsport is able to provide one MW of power is considered the same as an hour in which the facility is able to operate at full power, which for Edwardsport is 586 MW in the summer and 618 MW for the other months of the year. Moreover, availability has nothing to say about the economics of a particular plant. The cost of operating a plant does not dictate its availability, but cost certainly has a *major* impact on whether a plant is dispatched or not.

Therefore, capacity factor is the more important measure because it reflects how much energy (that is, how many MWh) the power plant actually generates during the period of time, which is a function of availability, power level *and* cost. And generation is what is important to Duke's ratepayers. As Duke witness Hager explained in her March 2011 testimony in IGCC-4S1:

> [T]he IGCC Project is projected to be the first Duke Energy Indiana plant dispatched to meet customers' energy needs because of its projected low fuel costs. Thus, from the day it is operational, it will be displacing less efficient and less environmentally friendly units, serving to reduce operating costs and thereby benefitting

---

1 Stultz IGCC-13 Testimony, at page 14, lines 3-9.

customers.[2]

Q. Please explain why this is so.

A. Duke's ratepayers are being forced to pay very high fixed costs for Edwardsport because of the plant's expensive construction cost and fixed operating costs. Duke's ratepayers are only able to offset even a portion of these very high fixed costs if the plant consistently generates large quantities of low cost energy (MWh) that displace higher cost power that would otherwise be generated at other Duke plants or purchased from the MISO energy market. For this reason, Duke's ratepayers are vitally interested in how much energy the plant actually generates and the plant's capacity factor, not its availability, is a measure of this.

Q. Mr. Stultz claims that availability is the better measure than capacity factor because there are factors well beyond an operator's control that will affect the capacity factor of a unit.[3] Do you agree?

A. No. Because Edwardsport was being self-scheduled by Duke rather than dispatched by MISO, nearly everything about Edwardsport's capacity factor during the IGCC 12 & 13 review period was within the operator's control. So this portion of Mr. Stultz's testimony is completely irrelevant to the period under review in this proceeding. Nevertheless, his claim that a plant's availability is a better measure than its capacity factor is wrong for any time period because, as I just discussed, ratepayers are vitally concerned with how much energy Edwardsport will produce and at what cost. Capacity factor, not availability, is the appropriate measure to reflect that concern.

---

[2] Supplemental Testimony of Janice Hager in IGCC-4S1, Duke Exhibit TT, March 10, 2011, page 3, lines 6-10, https://myweb.in.gov/IURC/eds/Modules/Ecms/Cases/Docketed_Cases/ViewDocument.aspx?DocID=0900b6318015df68.

[3] Stultz IGCC-13 Testimony, at page 14, lines 10-17.

Q. Have you seen any evidence that Duke itself believes that availability is not the best measure for evaluating a power plant's operating performance?

A. Yes. On October 11, 2014, Lynn J. Good, Duke Energy's President & Chief Executive Officer asked Dhiaa M. Jamil, Duke's Executive Vice President & President of Regulated Generation, for an update on Edwardsport's operating performance during August and September 2014.[4] Table 1, below, replicates the information that Mr. Jamil provided in response to Ms. Good's request.

[4] The e-mail exchange between Ms. Good and Mr. Jamil, received by JIs in DEI's Attachment CAC 1.7-B, is included as Exhibit DAS-2.

Table 1: **Internal Duke Energy Report on Edwardsport's Operating Performance from June 2013 through September 2014.**

	Site Capacity Factor (Natural Gas & Syngas)	Capacity Factor (Syngas Only)	Equivalent Availability Factor (Natural Gas & Syngas)	Gasification Availability Factor
Sep-14	14.93	13.34	27.13	26.57%
2014 YTD	40.75	35.96	65.96	55.35%
Q3, 2014	48.45	45.76	60.88	69.66%
Jun-13	12.38	9.92	82.37	21.53%
Jul-13	26.19	7.96	68.97	14.45%
Aug-13	60.39	50.56	80.83	76.01%
Sep-13	31.66	24.83	63.36	47.96%
Oct-13	43.31	40.84	61.32	58.60%
Nov-13	28.28	22.77	65.87	32.19%
Dec-13	32.39	19.5	61.46	41.69%
Jan-14	17.54	2.3	60.78	4.84%
Feb-14	5.21	0.12	41.72	0.61%
Mar-14	32.77	26.92	77.25	50.93%
Apr-14	37.99	33.89	68.26	61.56%
May-14	66.8	65.68	87.77	82.79%
Jun-14	58.39	54.86	73.02	84.74%
Jul-14	67.63	63.47	79.27	90.99%
Aug-14	61.7	59.42	75.15	90.02%
Sep-14	14.93	13.34	27.13	26.57%
Cumulative thru September 2014	37.63	31.27	67.36	49.78%

It is extremely noteworthy that Mr. Jamil, whose overall management responsibilities include Edwardsport, did not include the plant's overall availability as a measure of Edwardsport's operating performance in this report to Duke Energy's President & Chief Executive Officer. Instead, he included four separate measures of Edwardsport's operating performance: its capacity factor on both syngas and natural gas; its capacity factor on syngas; its Equivalent Availability Factor (EAF) on both natural gas and syngas; and its Gasification

Availability Factor.[5] This is directly contrary to Mr. Stultz's claim that the plant's overall availability on syngas and natural gas is the best measure as Mr. Jamil's report did not even mention Edwardsport's overall availability in response to Ms. Good's request for an update on Edwardsport's operating performance.

Q. Is there anything else that is significant about the information in Table 1, above, that Mr. Jamil reported to Ms. Good?

A. There are two other critical facts readily apparent from the information that Mr. Jamil reported to Ms. Good, in addition to the fact that it appears that Duke's senior management does not consider Edwardsport's overall availability to be as significant a measure of its operating performance as its capacity factor.

1. The information in Table 1 reinforces my conclusion, as presented in Figures 1 through 11, below, that Edwardsport's operating performance during the IGCC-12 and 13 review periods was extremely poor.

2. This information also shows operating performance has continued to be poor beyond the March 31, 2014 end of the IGCC-13 review period.

Q. Even if the IURC were to accept that availability is one of the best measures for evaluating Edwardsport's operating performance, do the monthly availability factors from Mr. Stultz accurately and reasonably reflect the plant's overall availability during the IGCC-12 & 13 review periods?

A. No. The availability factors presented by Mr. Stultz severely overstate Edwardsport's availability during the IGCC-12 & 13 review period in a number of ways.

---

[5] The Equivalent Availability Factor included in Table 1 differs from the Availability Factor discussed by Mr. Stultz in that it reflects the hours during which the plant operated at less than full power as well as the hours when it was not operating. Consequently, it is a better measure of the plant's overall operating performance than the Availability Factors discussed by Mr. Stultz in his testimony at pages 12-16.

First, and most significantly, Mr. Stultz's availability factors reflect both the hours when the plant was available on syngas and the hours when it was available on natural gas. However, Edwardsport is intended to be an IGCC plant that burns syngas. Duke originally projected that Edwardsport's would achieve an 85 percent annual availability on syngas in every year immediately after beginning commercial operations. This was subsequently changed to a forecast that the plant would achieve a 75 percent availability, again just on syngas, during its first 15 months of operations. Thus, if the Commission wants to consider Edwardsport's availability during the IGCC-12 and 13 review periods, it should examine the plant's availability on syngas, not its availability on both syngas and natural gas.

Second, Mr. Stultz's availability factors do not reflect that Edwardsport only achieved its 586 MW summer net capacity rating during a single hour in August 2013 and that it never achieved its 618 MW non-summer net capacity rating.[6] Nor do Mr. Stultz's availability factors reflect that Edwardsport's full power capacity rating is significantly lower when burning natural gas than when the plant is burning syngas. For example, Edwardsport's net full power capacity rating when burning natural gas is only 458 MW during the summer months as compared to its 586 MW net full power capacity rating while burning syngas. Mr. Stultz's availability factors also do not reflect the fact that the plant often operated at less than its rated capacity due to forced deratings from equipment problems and technical issues.

Third, some of the information that Mr. Stultz used to develop his monthly availability factors is questionable. For example, Mr. Stultz's availability factor for June 2013 is 99.72 percent. This reflects only [redacted] hours of unavailable time for Edwardsport. However, the plant experienced a full trip on June 13, 2013 that

---

6 Duke response to OUCC 15.16 is included as Exhibit DAS-3. Confidential Attachment to OUCC 15.16 is included in my workpapers.

kept it shut down for the remainder of the month – a period of some 424 hours.[7] But Mr. Stultz reflects virtually none of this outage time in his availability factor for that month.

Finally, Edwardsport has been offered to MISO as a must run unit for those periods when it was available on syngas or was performing testing while running on natural gas. According to the Company's confidential attachment to CAC 6.9,[8] Mr. Stultz's monthly availability figures reflect some [redacted] hours during the IGCC-12 and 13 review periods when the plant was available to operate on natural gas without any testing going on. Duke claims that during these hours the plant was offered to MISO for economic dispatch. It is very significant that, if correct, despite being offered for economic dispatch for some [redacted] hours while it was operating on natural gas (but no testing was being done), MISO only selected Edwardsport for dispatch in a single hour in March 2014, and Duke declined to run the plant in that hour. This would have been an indication of the plant's high operating costs on natural gas and its relatively poor economics compared to other generators in MISO.

Q. You mention that the monthly availability factors presented by Mr. Stultz are inflated because they combine both the hours when the plant was available on syngas and hours when it was available on natural gas. How do Mr. Stultz's availability factors on both syngas and natural gas compare to Edwardsport's monthly availability just on syngas?

A. Figure 1, below, compares the monthly availability factors on both syngas and natural gas with its monthly gasification availability. As can be seen from this comparison, its gasification availability was much worse than Mr. Stultz's

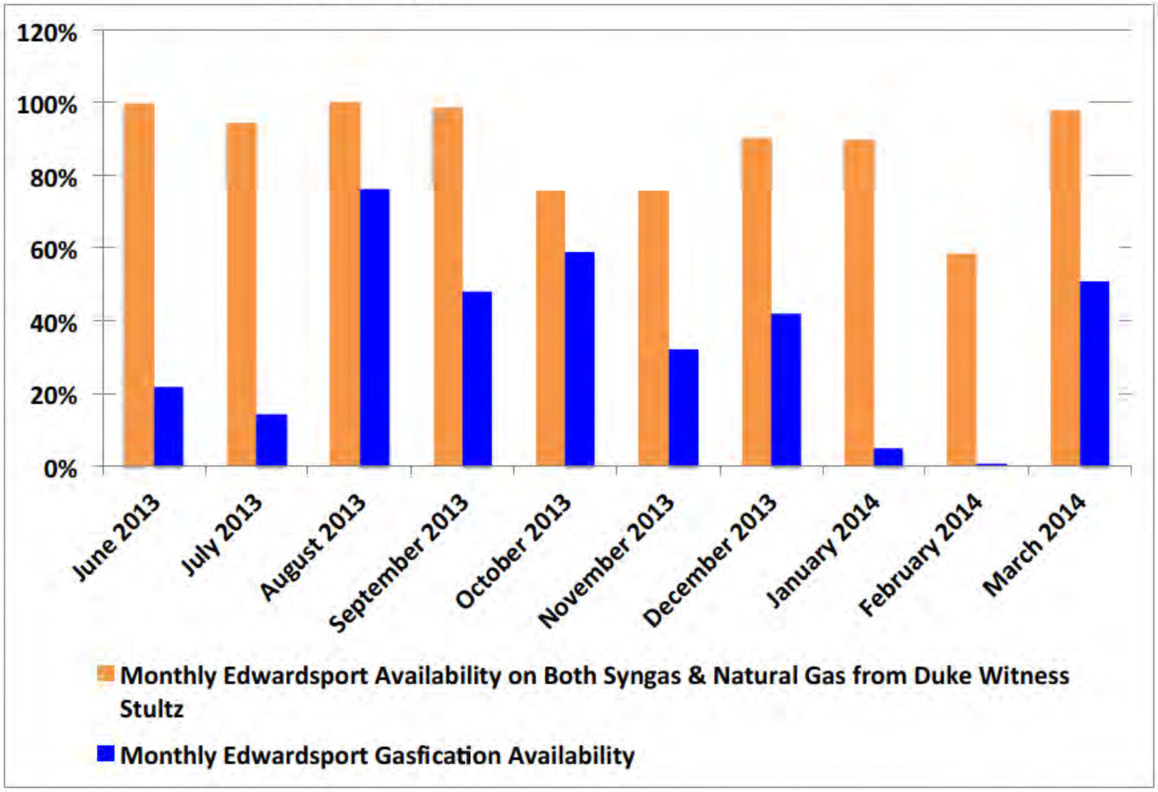
---

7 *See* the Edwardsport IGCC Progress Report No. 62 for July 2013 and No. 67 for December 2013.

8 Please see DEI Confidential Attachment to CAC 6.9 in my workpapers.

testimony would suggest. This is the more appropriate measure as Edwardsport is intended to be an IGCC plant that burns syngas.

Figure 1: Stultz Monthly Availability Factors vs. Edwardsport's Gasification Availability



In fact, Edwardsport's gasification availability for the entire period June 2013 through March 31, 2014, was only 35 percent or far less than the 88 percent availability on both syngas and natural gas presented by Mr. Stultz.

Q. Are you testifying that Edwardsport's monthly gasification availability is the best measure for evaluating the plant's performance?

A. No. The gasification availability factors presented in Table 1 and Figure 1 still do not reflect the plant's actual generation and, therefore, are not as important as a measure of its operating performance as its monthly capacity factors. Moreover, it is not clear whether the monthly gasification availability factors presented in

Table 1 and Figure 1 reflect those hours when Edwardsport's power output was derated (that is reduced) due to equipment problems and technical issues.

Q. Have you seen any instance where Mr. Stultz has testified that a plant's availability should be adjusted to reflect any hours in which it was not able to generate at full power?

A. Yes. Mr. Stultz had the following exchange with CAC counsel during the November 7, 2011 hearing in IGCC-4S1, Phase 1:

> Stultz: Availability takes into consideration derate hours as well as full unit hours, and the derate hours are adjusted based on the percent derate.
>
> Polk: All right. So if you had a unit that was available for 100 hours but at a 50 percent derate, that would be – that would yield an availability of 50 hours instead of 100 hours?
>
> Stultz: It would yield an equivalent availability of 50.[9]

Consequently, it appears that Mr. Stultz was testifying that the appropriate measure to use to evaluate Edwardsport's operating performance was its Equivalent Availability Factor (EAF), not its Availability Factor. Power plant EAFs reflect both the hours when the plant is unavailable to generate any power and the hours during which it is unavailable to generate at its full power rating. Unfortunately, Duke has not made any such adjustment in calculating the availability factors Mr. Stultz has presented in this proceeding.

Q. Should the Commission then rely on the monthly EAF figures presented in Table 1, above, as a measure of Edwardsport's operating performance?

A. No. Although I believe that EAF, in general, can be a meaningful measure of a plant's operating performance, I believe that the Company's EAF figures in Table 1 overstate Edwardsport's operating performance because they reflect both the

---

[9] Hearing Transcript, page P-11, lines 4-13.

hours when the plant was available (albeit at reduced output) on syngas and the hours when it was available (again, albeit at reduced output) on natural gas. Edwardsport's gasification EAF would be the more appropriate measure. Unfortunately, that information was not reported to Ms. Good in Table 1 in Exhibit DAS-2.

Q. If the availability figures discussed by Mr. Stultz's are so overstated, why then do you think that the Company has chosen to focus on Edwardsport's combined availability on both syngas and natural gas?

A. I think, quite simply, that Duke has chosen to focus on Edwardsport's overall availability on syngas and natural gas because, as shown in Table 1, above, and Figures 2 through 9, below, its operating performance under other, and more meaningful, measures has been very dismal and far worse than the Company had previously predicted when it was attempting to convince the IURC that completion of Edwardsport as an IGCC plant was the lowest cost option for ratepayers.

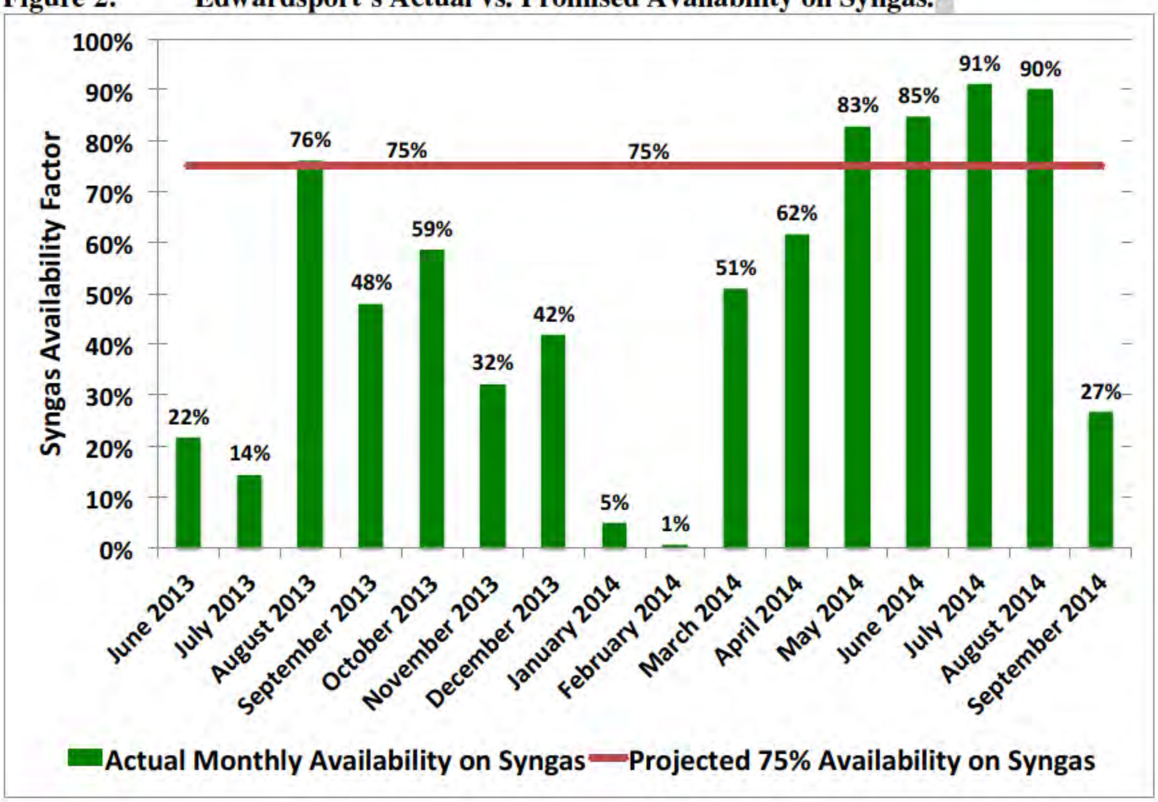
Q. What did the Company project for Edwardsport's availability during its initial months of operation?

A. For years, Duke's witnesses testified that Edwardsport would achieve an 85 percent availability on syngas "right out of the box" once it was designated as being in-service, with an even higher availability if operations on natural gas were included. Beginning in 2011, however, the Company adopted the position that Edwardsport would achieve a 75 percent availability on syngas during its first 15 months of operation. As the IURC itself noted in its Final Order in IGCC-4S1 when referring to Mr. Stultz's testimony in that proceeding: "He anticipates that during the first 15 months of commercial operation, 75% is a reasonable availability rate for the IGCC project operating on syngas…."[10]

Q. What has been Edwardsport's actual availability on syngas since the unit was designated as being in-service on June 7, 2013?

A. Figure 2, below, compares Edwardsport's actual monthly availability on syngas to the 75 percent availability on syngas that the Company projected in IGCC-4S1 in 2011.

Figure 2: Edwardsport's Actual vs. Promised Availability on Syngas.[11]



Thus, Edwardsport's availability on syngas for the ten-month period from June 2013 to March 2014, the months during the IGCC 12 & 13 review period when it

[10] At page 14.

[11] Edwardsport's actual monthly availability on syngas comes from Exhibit DAS-2.

was "in-service" according to Duke, was only 35 percent. The plant's availability on syngas for the sixteen-month period June 2013 through September 2014 was only 50 percent.[12] Both of these were far below the 75 percent availability on syngas that Duke assumed in the 2011 cost effectiveness modeling the Company used in IGCC-4S1 to argue to the IURC that completion of the project as an IGCC plant was the most economic option. And it is possible that even the monthly syngas availability numbers in Figure 1 are inflated because they may not account for the ability, or the inability as the case may be, of the gasifiers to produce enough syngas to power the plant at full load.

Q. What capacity factor did Duke project Edwardsport would achieve during its first months of commercial operation?

A. Duke's reduced availability modeling runs in IGCC-4S1 projected a 72 percent capacity factor on syngas during the plant's initial year to 15 months of operation.

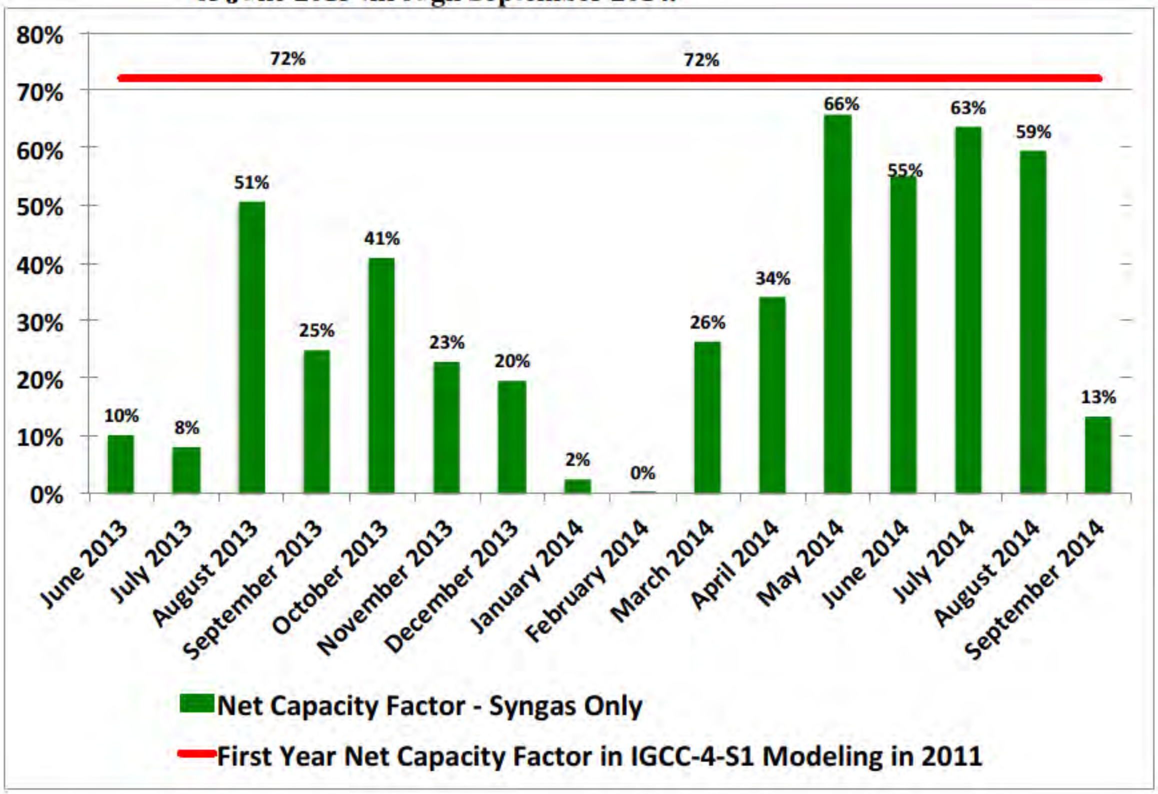
Q. What has been Edwardsport's actual capacity factor on syngas since the plant was declared "in-service" on June 7, 2013?

A. As shown in Figure 3, below, Edwardsport's monthly capacity factors on syngas for the months of June 2013 through September 2014 were significantly worse than the 72 percent average capacity factor that was forecast by the Company in Cause No. 43114 IGCC-4S1.

---

[12] *See* Exhibit DAS-2.

Figure 3: Edwardsport's Monthly Capacity Factors on Syngas for the Months of June 2013 through September 2014.[13]



The monthly capacity factors shown in Figure 2 represent an average 21 percent capacity factor for the ten-month period, June 2013 through March 2014, and a 31 percent average capacity factor for the sixteen-month period, June 2013 through September 2014. Clearly then, the plant's actual operation on syngas has been much worse than the 72 percent average capacity factor that Duke forecasted in Cause No. 43114 IGCC-4S1.

Q. What has been Edwardsport's actual operating performance on both syngas and natural gas since the plant was declared "in-service" on June 7, 2013?

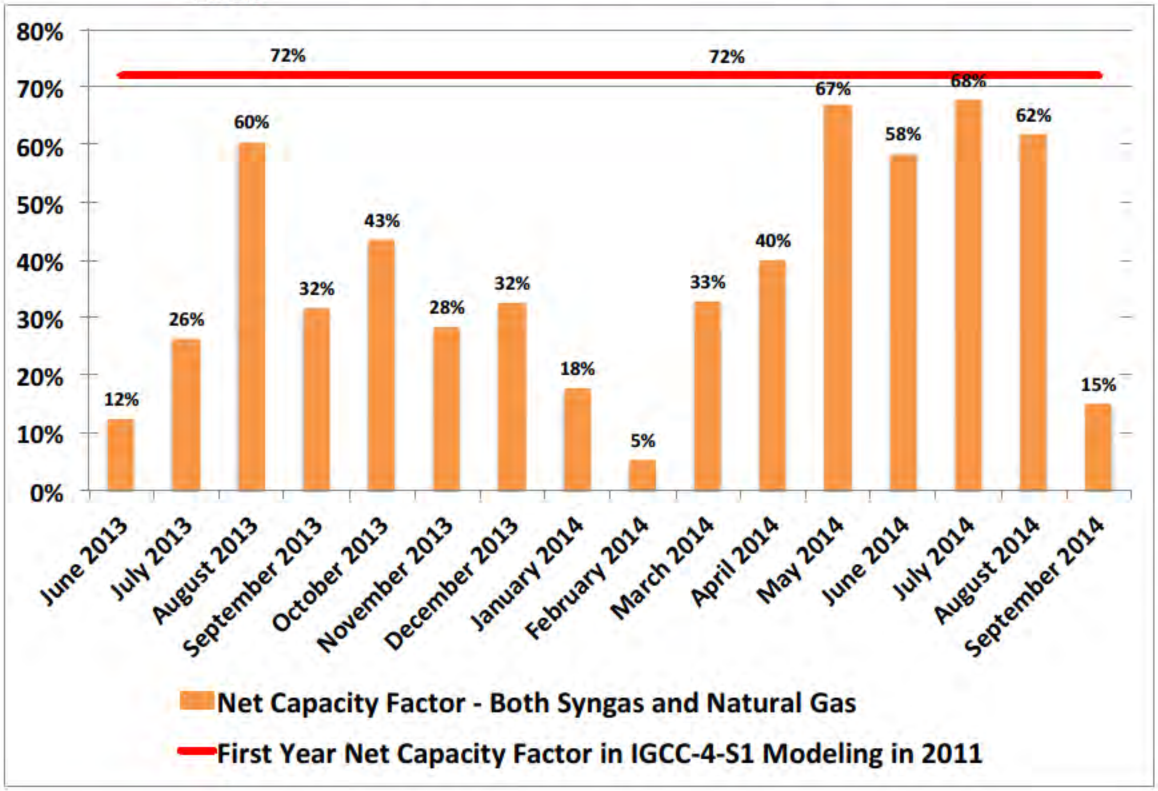
A. Edwardsport's monthly capacity factors on both syngas and natural gas for the period June 2013 through September 2014 also have been significantly worse

---

13 The actual monthly capacity factors on syngas and both syngas and natural gas come from Exhibit DAS-2.

than the 72 percent average capacity factor that the Company had forecast for syngas alone in Cause No. 43114 IGCC-4S1, as shown in Figure 4, below.

Figure 4: Edwardsport's Monthly Capacity Factors on Both Syngas and Natural Gas During the Months of June 2013 through September 2014.[14]



The monthly capacity factors shown in Figure 3 represent an average 31 percent capacity factor on both syngas and natural gas for the ten-month period, June 2013 through March 2014, and a 37 percent average capacity factor for the sixteen-month period, June 2013 through September 2014.

Thus, even if Edwardsport's total operation on both syngas and natural gas are considered, the plant's actual operating performance since it was designated as

---

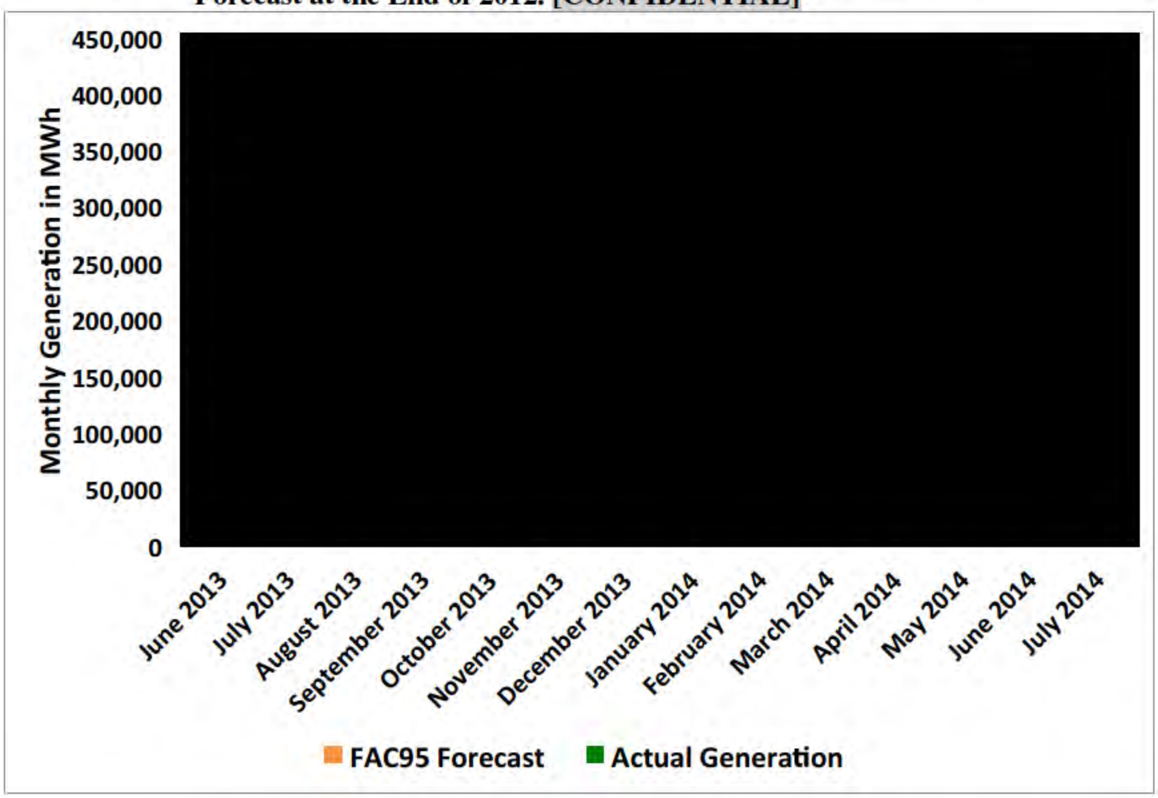
[14] The actual monthly capacity factors on syngas and both syngas and natural gas come from Exhibit DAS-2.

"in-service" by Duke has been extremely poor and far below what the Company said it would be back in 2011.

Q. How have Edwardsport's actual operations compared to more recent Company forecasts (rather than those presented by Duke in IGCC-4S1 in 2011)?

A. Figure 5, below, compares Edwardsport's actual net generation in the months of June 2013 through July 2014 with the net generation that the Company had forecast at the end of 2012 as part of Cause 38707 FAC-95.

Figure 5: Edwardsport's Actual Net Monthly Generation During the period of June 2013 through July 2014 compared to the Company's FAC-95 Forecast at the End of 2012. [CONFIDENTIAL][15]



---

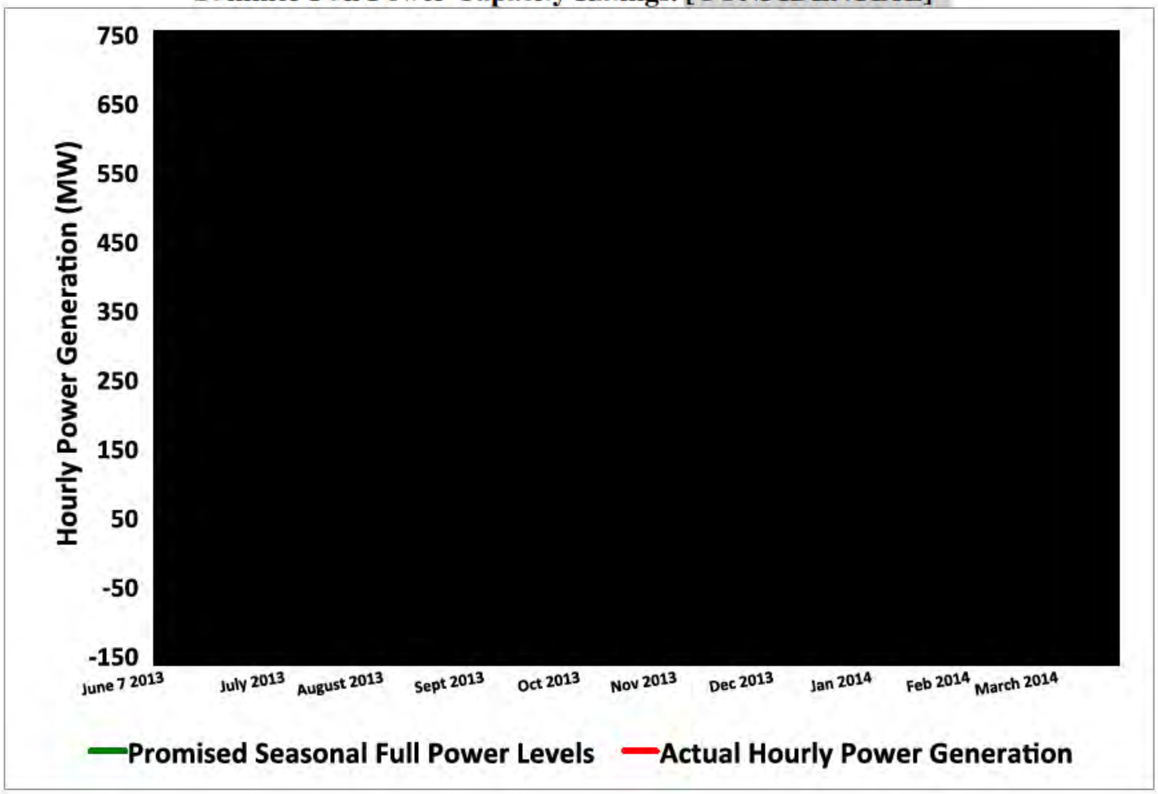
[15] The FAC 95 Forecast was provided as Confidential Attachment DEI-IG 5.11(attached as Exhibit DAS-4-Confidential) and the actual hourly plant output came from Duke's Confidential Response to DEI-IG 4.24 (attached as Exhibit DAS-5-Confidential).

Thus, Edwardsport's actual generation from June 2013 when the plant was declared to be "in service" through the March 31, 2014 end of the IGCC-13 review period was only [redacted] percent of what the Company had forecast for this period at the end of 2012, which is significant because it was Duke, not MISO, which determined when and for how long Edwardsport would operate.

Q. Has Edwardsport operated at a consistently high power level since the plant was declared to be "in service" on June 7, 2013?

A. No. The plant's performance has been very inconsistent during this period and, in fact, the plant only achieved its 586 MW summer net full power capacity output rating for only a single hour during this period. The plant never achieved its 618 MW net non-summer full power capacity rating at any time during the IGCC 12 and 13 review periods. This can be seen in Figure 6 below.

Figure 6: Edwardsport's Actual Hourly Net Power Generation for June 7, 2013 through March 31, 2014 vs. Promised Summer and Non-Summer Full Power Capacity Ratings. [CONFIDENTIAL][16]



Thus, during the period June 7, 2013 through March 31, 2014, after the plant had been declared "in service" by Duke:

- Edwardsport only achieved its 586 MW net summer full power rated output for a single hour on August 9, 2013.
- Edwardsport never ran at its 618 MW net non-summer full power rating during the entire period between June 7, 2013 and March 31, 2014.
- Edwardsport's output only exceeded [redacted] MW in [redacted] hours, or approximately [redacted] percent of the total hours in the entire period.
- Edwardsport had a negative net generation (that is it was using more power from the grid than it put out into the grid) during almost [redacted] hours, or approximately [redacted] percent of the total hours in the period.

---

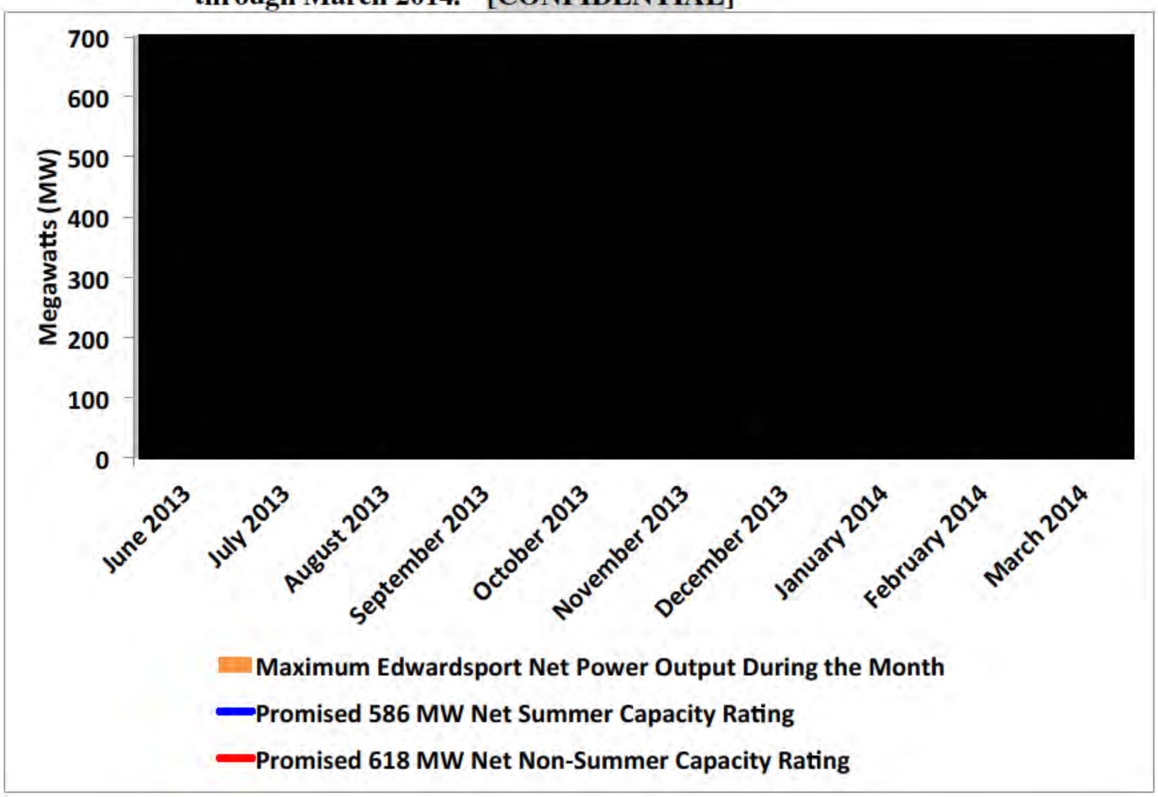
[16] The actual hourly plant outputs shown in Figure 2 are from DEI's Confidential Attachments OUCC 3.2-A and CAC 6.11-A, which are included in my workpapers.

- Edwardsport's average net power level during this period was only [redacted] MW or only approximately [redacted] percent of its projected full power.

Q. Figure 6, above, shows Edwardsport's hourly generation. What was the plant's maximum output in MW in each month of the period June 2013 through March 2014?

A. Figure 7, below, shows the maximum power output achieved by Edwardsport in each of the months between June 7, 2013 and March 31, 2014.

Figure 7: Edwardsport's Maximum Monthly Power Outputs in June 2013 through March 2014.[17] [CONFIDENTIAL]



---

17 The information in Figure 7 was taken from Duke's Confidential Attachments CAC 6.38-A and CAC 6.11-A, which are included in my workpapers.

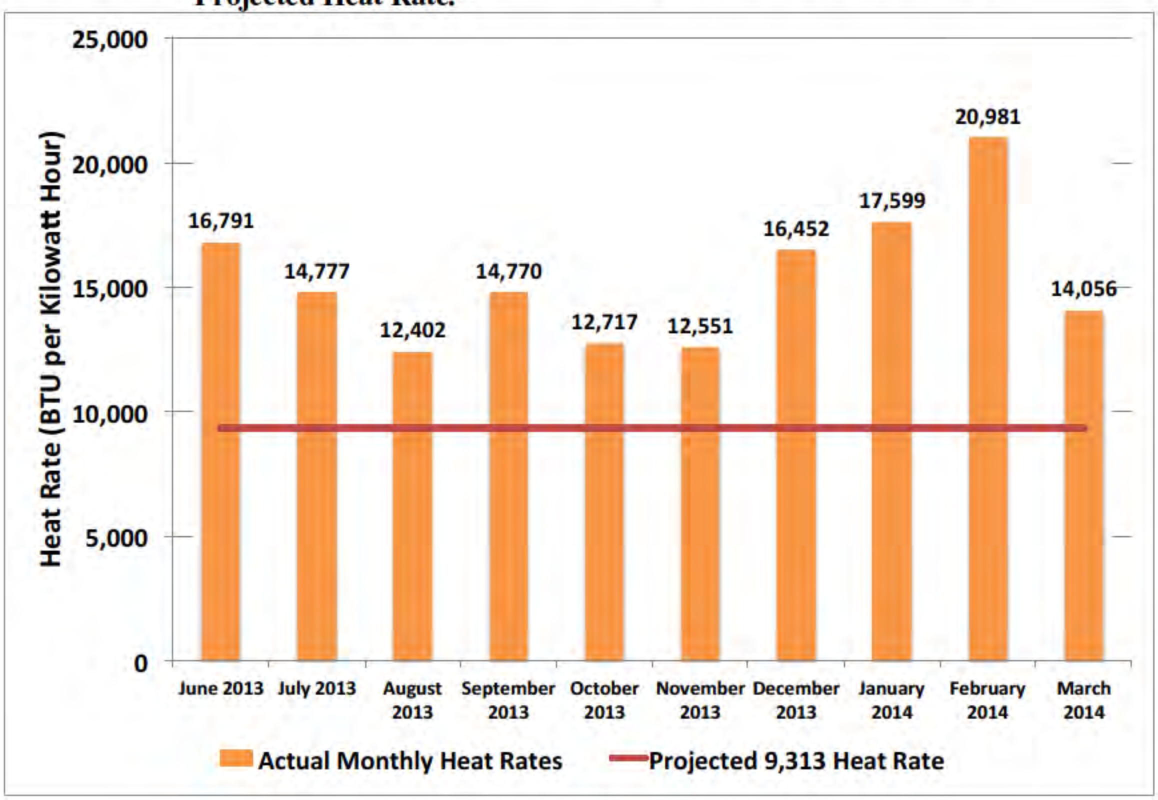
Q. What did Duke forecast would be Edwardsport's heat rate?

A. In April 2010, when Duke witness Womack filed his Direct Testimony in IGCC-4S1, the Company was projecting a 9313 BTU/KWH heat rate for Edwardsport.[18]

Q. Did the Company achieve this heat rate in the IGCC-12 & 13 review period?

A. No. As shown in Figure 8, below, Edwardsport's actual monthly heat rates have been significantly worse than the Company told the Commission back in April 2010.

Figure 8: Edwardsport's Actual Monthly Heat Rates vs. 9313 BTU/KWh Projected Heat Rate.[19]



[18] Direct Testimony of W. Michael Womack in IGCC-4S-1, filed in April 2010, at page 36.

[19] Edwardsport's monthly actual station heat rates were provided in Duke's declassified response to SDI 1.3, which is attached as Exhibit DAS-6.

Q. Has Duke offered any explanation for why Edwardsport's actual heat rates are so much higher than the Company had projected?

A. No. However, a plant that has as many stops and starts and that operates at a power level so far below full power as Edwardsport did through March 2014 will necessarily have a higher heat rate. Available evidence also suggests that the plant's heat rates are being increased by larger than predicted parasitic loads, as well as inefficiencies in the conversion of coal to syngas. If Edwardsport continues to have such higher heat rates going forward into the future, Duke's ability to have the plant economically dispatched by MISO would be severely compromised. This would hurt ratepayers by leading to higher fuel and purchased power costs than if Edwardsport operated at the predicted and supposedly guaranteed heat rates.

Q. Is there any other commonly accepted measure by which the IURC should evaluate Edwardsport's operating performance since the plant was declared "in-service" by Duke in June 2013?

A. Yes. Another commonly accepted measure for evaluating a power plant's operating performance is its Equivalent Forced Outage Rate (EFOR). EFOR is a measure of the probability that a unit will not be available due to forced outages of the entire plant and deratings (that is, where the plant is available to generate but only a lower power output due to unplanned equipment problems or technical issues).

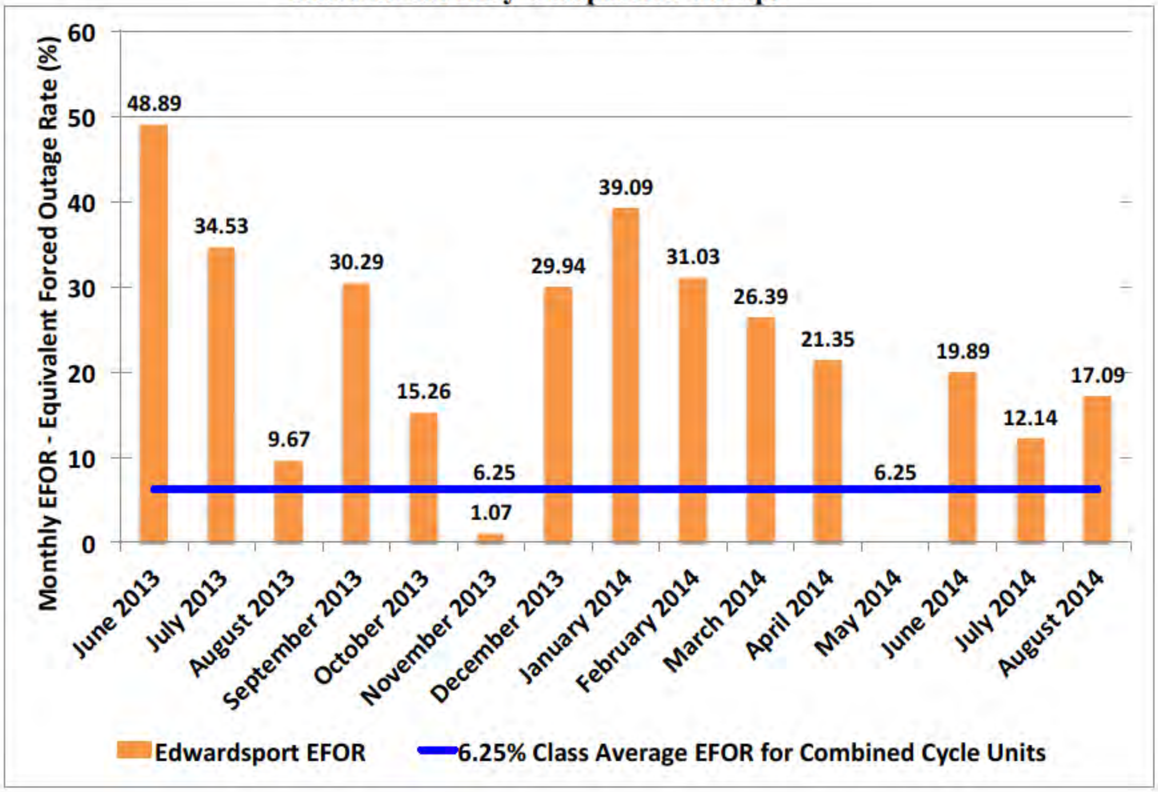
Q. How does Edwardsport's EFOR compare to that of comparable power plants?

A. Figure 9, below, compares Edwardsport's monthly EFORs for Duke to the average EFOR for combined cycle units.[20] This was the comparison group that Duke used in its 2013 Generator Verification Test Capacity submission to MISO in 2013.[21] As can be seen from Figure 9, Edwardsport's EFOR between June 2013 and August 2014 was dramatically higher than the average EFOR of what Duke believed to be the relevant industry comparison group.

[20] Unfortunately, as I was preparing this comparison, I realized that the Company had not provided Edwardsport's EFOR for the month of May 2014. Therefore, there is no bar in Figure 9 for that month.

[21] Duke's Response to CAC 16.1-16.3 is included as Exhibit DAS-7. Duke's Confidential Attachment to CAC 16.3-A is included as Exhibit DAS-8-Confidential.

Figure 9: Edwardsport's Monthly Equivalent Forced Outage Rate (EFOR) vs. Relevant Industry Comparison Group.[22]



In fact, Edwardsport had an average 26.62 percent EFOR for the entire period of June 2013 through the March 31, 2014 end of the IGCC-13 review period. This was more than four times higher than the average EFOR of the industry comparison group.

Q. Do you agree with Mr. Stultz's observation that "the plant has operated about where we expected it to in the early months of operation?"[23]

A. Not at all. I believe that this statement in Mr. Stultz's June 12, 2014 Testimony in IGCC-13 is a gross misrepresentation of Edwardsport's operations through the

[22] The Edwardsport monthly EFORs were provided in Duke's Confidential Response to CAC 20.01, which is included as Exhibit DAS-9-Confidential. The industry comparison group EFOR was taken from the NERC GADS statistical brochure for the years 2009-2013.

[23] Stultz IGCC-13 Testimony, at page 15, lines 13-14.

March 31, 2014 end of the IGCC-12 and IGCC-13 review periods at issue in this proceeding. By any reasonable measure, Edwardsport operated very poorly after it was declared to be "in-service" on June 7, 2013, and at levels far below what the Company had promised or forecast over the years.

More specifically:

(1) Edwardsport's availability on syngas was only 35 percent, far below the 75 percent availability on syngas that Duke had promised during IGCC-4S1 for the plant's first 15 months of operation.

(2) Edwardsport's actual capacity factor on syngas was only 21 percent, far below the 72 percent capacity factor that the Company had forecast in IGCC-4S1 for the plant's first year of operation. Its actual capacity factor on both syngas and natural gas was only 31 percent.

(3) Edwardsport's actual generation was less than one-half of what Duke had later forecast for the period June 2013 through March 31, 2014 at the end of December 2012, a mere six months before the plant was declared to be "in-service."

(4) Edwardsport generated 586 MW net, its summer month net capacity rating, for only a single hour during the summer months of the IGCC-12 and IGCC-13 review periods, and that was on August 9, 2013. Edwardsport never generated at its 618 MW net non-summer month capacity rating at any time during the IGCC-12 and IGCC-13 review periods.

(5) Edwardsport's actual monthly heat rates were much higher (that is, worse) than the 9313 BTU/KWh heat rate at which the Company had told the IURC the plant would operate.

(6) Edwardsport had a dramatically higher Equivalent Forced Outage Rate than the relevant industry comparison group.

This poor performance demonstrated that on June 7, 2013 or at any time through March 31, 2014, Edwardsport certainly was not in commercial operation or ready for commercial operation, i.e. to be dispatched economically by MISO on syngas as an IGCC plant with a summer net full power rating of 586 MW and a non-summer net full power rating of 618 MW.

DUKE'S DECLARATION THAT EDWARDSPORT WAS "IN-SERVICE"

Q. Did Duke provide the IURC with a consistent and comprehensive set of definitive technical or operational criteria by which it would determine when Edwardsport should be declared "in-service?"

A. No. Duke has repeatedly avoided wedding itself to any comprehensive set of definitive engineering or operational criteria for "in service." However, the Company did identify two pre-conditions for an "in-service" declaration. During the hearings in IGCC-4 and IGCC-4S1, Duke witnesses said on multiple occasions that dispatch of the plant by MISO, the "system load dispatcher" would indicate that Edwardsport was "in-service." At the same time, Duke witness Stultz testified that the Company would not place Edwardsport into service until it had operated the plant at full power. Unfortunately, Duke did not fulfill either of those preconditions.

For example, Duke witness Womack had the following exchange with Commissioner Ziegner during the April 6, 2010 hearing in IGCC-4:

> Womack: … What we're planning to do is to get the plant in good enough shape by the Summer of 2012 that we can interrupt testing and tuning of the equipment and run the plant to make load for customer demand that summer during high peak demand periods. There is a lot of details to be worked out in that game plan, a lot of interaction with MISO that we have to figure out as far as how that would exactly work, but we're pursuing that plan so that we can provide power even in the summer – during that summer even though we're not officially, substantially complete.
>
> Ziegner: And just so I'm clear, that would be prior to the August

> 27th new in-service date?
>
> Womack: Yes; yes. The new August 27th date that we're now projecting is the, if you will, substantial – formal, official, substantial completion date has the meaning that it always had. It would be what we call the in-service date. It would be the date at which we would hand the plant over and tell MISO it's fully dispatchable; do with it whatever you want; turn it on; turn it off, whatever. [24]

Duke witness Stultz similarly testified in IGCC-4S1 that once Edwardsport was operational, MISO would "perform economic dispatch and ultimately determine the capacity factor of the plant."[25] Mr. Stultz re-emphasized this point about MISO economically dispatching Edwardsport during cross-examination while, at the same time, indicating that the plant would be available at full power when it was available for dispatch.

For example, Mr. Stultz testified to the following in response to questions by Joint Intervenors' counsel Polk and Agnew:

> Polk: How do you define commercially available?
>
> Stultz: To me, I use the term that's been referred to in our working groups for years. It's used and useful, when it's available for dispatch to the benefit of the ratepayer.
>
> Polk: So is it your testimony that the plant will be available for dispatching at 600 megawatts of capacity come November of next year?
>
> Stultz: It's my testimony that that unit will be available at 618 megawatts for dispatch in late September –
>
> Polk: And how –
>
> Stultz: -- 2013.
>
> Polk: And how much will be bid into MISO at that time?
>
> Stultz: They'll bid whatever is available.

24 Hearing Transcript in Cause 43114 IGCC-4 on April 6, 2010 at pages 49 and 50.

25 Duke Exhibit FFF in IGCC-4S1, at page 3, lines 3-5.

> Polk: And how much will be available?
>
> Stultz: Well, we wouldn't take it commercial on a given day if it weren't 100 percent available at that point. That could change the next day just because of the complexity of power plants, but it will be available.[26]

And:

> Agnew: Do you know . . . when the dispatch decisions are going to be turned over to the ISO, the MISO?
>
> Stultz: Well, we'll remain in a testing phase until the end of September 2012, and at that point, we, by schedule today, will officially list the unit as commercial, and at that point, MISO will take responsibility for the dispatch and tell us when to put it on and take if off based on economics.
>
> Agnew: Okay, and that will be dispatched as a –
>
> Stultz: As a typical plant anywhere. At that point, the construction is not 100 percent done; there's some things that will be left like painting and potentially some road work or ditch work, but the plant itself will be fully operational, and it will work as any other plant in the Duke system.
>
> Agnew: Burning gasified coal?
>
> Stultz: Yes.**[27]**

Duke witness Womack gave similar testimony in response to questions from DEI Industrial Group counsel Stewart:

> Stewart: Well, you say there "We have chosen…," and I'm looking at Line 19, "…to use the reinstallation of the gas turbine rotor after GE's validation test as the trigger event for declaring 'in service.'"; is that right?
>
> Womack: That's correct, yes.

---

[26] Cause No. 43114 IGCC-4S1, Phase I, Hearing Transcript, November 7, 2011, pp. P-43 and P-44.

[27] Cause No. 43114 IGCC-4S1, Phase II, Hearing Transcript, December 15, 2011, pp. P-3 and P-4.

> Stewart: Now, would MISO be able to dispatch that plant at 600 megawatts at that point?
>
> Womack: Yes.[28]

Taken together, it is unambiguous that in 2011, Duke told the Commission that it intended Edwardsport to be "in-service" when the full capacity of the plant was economically dispatchable by MISO. However, the plant was neither available at full load nor economically dispatchable by MISO when it was declared "in-service" by Duke on June 7, 2013. More than a year later, Edwardsport still has not met the standard the Company gave the Commission in IGCC-4S1.

Q. Just to be clear, did Edwardsport operate at 100 percent power at any time prior to June 7, 2013 when Duke declared it was "in-service"?

A. No.[29] Edwardsport generated a maximum of between [redacted] MW and [redacted] MW of net power in eight hours during the days preceding June 7, 2013. This was far below the plant's 586 MW summer seasonal net 100 percent power rating.

Q. At any time prior to June 7, 2013, was Edwardsport offered to MISO for economic dispatch while the plant was operating on syngas?

A. No.

Q. At any time prior to June 7, 2013, did Duke state that Edwardsport would only be declared "in-service" after startup testing was completed?

A. Yes. In IGCC-8 the Company stated that the plant would be declared "in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility."[30]

---

[28] Cause No. 43114-IGCC-4S1, Phase II, Hearing Transcript, December 13, 2011, pp. M-72-M-73.

[29] Duke's Confidential Attachment to OUCC 3.2-A is included in my workpapers.

[30] Duke Response to CAC 4.4 in Cause 43114 IGCC-8 is included as Exhibit DAS-10.

Q. Was testing completed at Edwardsport by the time when Duke declared the plant to be "in-service" on June 7, 2013?

A. No. Edwardsport had not completed either the GE New Product Introduction (NPI) testimony or its preoperational and startup testing before Duke declared the plant "in-service" on June 7, 2013. Consequently, it is impossible to see how Duke could have decided in early June 2013 that Edwardsport was ready for its intended use as an integrated gasification combined cycle generating facility before the NPI and preoperational and startup testing that was necessary to assure that the plant would run as it was intended to run had been completed.

Q. When was the GE NPI testing completed?

A. The exact date when Duke and GE completed the required NPI testing is unclear. However, Duke has most recently said that GE's NPI testimony was completed by September 2013, or three months after the plant had been declared to be in-service.[31]

Q. Was the NPI testing just for the benefit of GE or was it an integral part of the plant's testing?

A. The NPI originally was an integral part of the overall Edwardsport plant testing but as the schedule became extended and costs escalated, Duke looked for ways to reduce the testing period and to rush the plant into service. Consequently, the Company began to differentiate between an "in-service" date and the date when the plant would be substantially completed.

[31] Duke Response to DEI-IG 8.2 is included as Exhibit DAS-11.

Q. Had the Company completed Edwardsport's integrated performance testing as of June 7, 2013?

A. No. The Company's startup testing program included the integrated preliminary and final capacity and heat performance tests that were not completed until April and May 2014, that is, after the March 31, 2014 end of the combined IGCC-12 and 13 review period.[32]

Q. Was this integrated performance testing merely a condition of the contract with GE?

A. The performance testing was required under its contract with General Electric and pursuant to ASME Standard PTC 47, which is the industry standard for the testing of IGCC plants.[33]

Q. Were there other important integrated plant performance tests also not completed as of the March 31, 2014 end of the IGCC-13 review period?

A. Yes. The plant ramping test was not completed until August of 2014. The plant's operability tests were completed November 12, 2014.[34]

Q. How long did Duke initially claim that it would take to achieve "substantial" completion after Edwardsport was "in-service"?

A. In his Settlement Rebuttal Testimony in IGCC-4S1, Company witness Womack testified that it was then Duke's "best estimate" that Edwardsport should be "in-service" sometime early in the first quarter of 2013, with substantial completion occurring in the second quarter of 2013, i.e. approximately three months later.[35]

---

32 Duke's Third Supplemental Response provided on 12-5-2014 to DEI-IG 1.8 is included as Exhibit DAS-12.

33 Duke Response to OUCC 15.18 is included as Exhibit DAS-13.

34 Duke Supplemental Response to DEI-IG 8.03 is included as Exhibit DAS-14.

35 Petitioner's Exhibit LLL, July 6, 2012, at page 5, lines 20-21.

Q. When did the plant achieve "substantial completion" and "final completion" as defined in the contract with General Electric?

A. The plant has not yet achieved the milestone of "substantial" completion, more than eighteen months after it was declared "in-service" by Duke.

Q. When does Duke currently anticipate that Edwardsport will achieve the "substantial completion" and "final completion" milestones?

A. The Company's recent response to DEI-IG 1.8 states that Duke Energy Indiana currently expects that substantial completion will be achieved by the end of 2014 and the final completion will be achieved in the spring of 2015.[36]

Q. If by June 7, 2013, Edwardsport had not operated at 100 percent power while operating on syngas, had not achieved substantial completion, had not been offered to MISO for economic dispatch while operating on syngas and had not completed its preoperational and startup testing, then what criteria did Duke use to declare Edwardsport "in-service"?

A. Internal Duke e-mails show that the Company decided it would declare Edwardsport as being "in-service" after both gasifiers had run in parallel for five days or 120 hours of non-consecutive operation.[37]

Q. Did the plant complete 120 hours of parallel running of both gasifiers prior to its being declared in-service on June 7, 2013?

A. No. Duke rushed the plant into service after the gasifiers had only run in parallel for 53 hours.

---

36 *See* Exhibit DAS-12.

37 *See* 43114 IGCC 12 & 13, DEI Confidential Attachment CAC 4.2-A, BS 090015313-0002551; 43114 IGCC 11, DEI Confidential Attachment 1.4-A, BS 090002913-0000193; 43114 IGCC 11, DEI Confidential Attachment CAC 4.6-A, BS 090002913-0001203. These emails have been included as Exhibit DAS-15-Confidential.

Q. Did the gasifiers run in parallel for a total of 120 hours at any point in June 2013?

A. No. The plant entered an extended outage on June 13, 2013, at which point the gasifiers had only run in parallel for a total of 119 hours.[38]

Q. Was Duke the only entity that decided that Edwardsport was "in-service" beginning on June 7, 2013?

A. Yes. No other entity (e.g., MISO or the IURC) took part in the decision.[39]

Q. When did Edwardsport achieve full power operation?

A. Edwardsport generated 586 MW (net) of power, its summer full power rating, for a single hour on August 9, 2013, coming close for a second hour on the same day. The plant did not generate 618 MW (net) of power, its non-summer full power rating, during any hour in the IGCC 12 & 13 review period. Indeed, the plant did not achieve stable generation at or near its rated capacity for a period of time sufficient to perform even its Preliminary Performance Test under Section T of Duke's contract with GE until shortly before that Test was conducted on April 2, 2014.[40]

Q. Was Edwardsport offered for economic dispatch by MISO during the IGCC 12 & 13 review period?

A. When the plant has been operating on syngas or when testing was being performed while it was operating on natural gas, Edwardsport has been self-scheduled by Duke and designated as a "must run" unit and its output has been

---

38 Cause No. 43114 IGCC 11, Duke's Supplemental Response to CAC Data Request 2.1(b) is included as Exhibit DAS-16.

39 Duke Response to OUCC 15.2 is included as Exhibit DAS-17.

40 Compare DEI Confidential Attachment CAC 1.6-E, BS 090015313-0005207 with DEI Confidential Attachment CAC 1.6-E, BS 090015313-0004777, which are included as Exhibit DAS-18-Confidential.

recorded as test generation.[41] During those hours when the plant was running on natural gas but no testing was being done, the unit was offered to MISO for economic dispatch.

Q. Did MISO actually dispatch Edwardsport at any time during the IGCC-12 and 13 review period?

A. No. Edwardsport was not economically dispatched by MISO during the IGCC 12 and 13 review periods.[42] From April 2013 through March 2014, all of the energy generated by Edwardsport was offered to MISO with a commit status of Must Run, according to Duke's responses to data request CAC 2.1(a) and its Supplemental Responses to CAC 6.8 and 6.10.

However, there appears to have been one instance in March 2014 when MISO called upon the plant to operate but Duke declined to start the plant at that time.

Q. Did the plant continue to be offered as "must run" after the March 31, 2014 end of the IGCC 12 & 13 review period?

A. Yes. Edwardsport was still being offered as "must run" at least through the start of the fall 2014 outage which began in September.[43]

Q. What are the Company's current plans for offering Edwardsport for economic dispatch by MISO?

A. According to the testimony filed by Company witness Swez in 38707-FAC-101, Duke has planned to no longer designate Edwardsport as "must run" by MISO only after coming out of the fall 2014 outage, which I believe occurred sometime

---

41 Duke Responses to CAC 2.1(a), CAC 6.8, and CAC 6.10 are included as Exhibit DAS-19.

42 *See* pp. 1-3 of Exhibit DAS-19.

43 Cause No. 38707 FAC 102, Petitioner's Exhibit 6, pp. 20-24.

in the first two weeks of October.[44] However, it is unclear whether Duke actually has done so.

Q. Did Edwardsport meet the preconditions promised by the Company for an "in-service" declaration either by June 7, 2013 or by the March 31, 2014 end of the IGCC-12 and 13 review periods?

A. No. Edwardsport had *not* satisfied *any* of its own preconditions either by the time Edwardsport was declared to be "in-service" on June 7, 2013 or by the March 31, 2014 end of IGCC-12 and IGCC-13 review periods.

- Duke had not shown that Edwardsport was ready to operate consistently and reliably at full power as an IGCC plant burning syngas.
- Edwardsport has not been economically dispatched by MISO while operating as an IGCC plant burning syngas.
- Duke had not completed Edwardsport's preoperational startup testing.

Q. Has the IURC previously ruled whether an IGCC power plant had met the criteria necessary to be declared "in-service"?

A. Yes. The Commission determined in its Final Order in Cause No. 40003 issued on September 27, 1996, that the Wabash River Coal Gasification Repowering Project (WRCGRP) had met the criteria to be declared "in-service."

Q. In your opinion is the IURC's decision regarding whether the Wabash River CGRP was "in-service" relevant to Edwardsport?

A. No. The Wabash River CGRP "in-service" determination is clearly distinguishable in several critical respects from the situation with Edwardsport:

---

[44] *Id*.

(1) The Wabash River plant was a U.S. Department of Energy (DOE) demonstration project for which the total cost and rate impact were dramatically lower than Edwardsport – and DOE was paying 50 percent of the construction costs.

(2) Destec, not PSI, was the owner and responsible party for the gasification process used at Wabash River. Therefore, its capital costs were not being included in PSI's rate base and the Company's customers were only paying for the plant's output when they received it as a fuel cost.

(3) With Edwardsport, the Company made express representations to the Commission and its ratepayers in advance regarding key preconditions as to its availability for MISO dispatch at 100% of its rated capacity prior to an "in-service" declaration which had not been made prior to the WRCGP "in-service" declaration.

(4) The Commission approved a Settlement in Cause No. 43114-IGCC-4S1 which established an "in-service" standard that Edwardsport be in commercial operation or ready for commercial operation which all parties and the Commission understood to incorporate the Company's representations regarding the plant's availability on syngas for MISO dispatch at or near 100% of its rated capacity.

(5) Finally, unlike the Wabash River proceeding, here the Commission has overwhelming evidence as to how extremely poorly Edwardsport actually has performed since Duke declared it to be "in-service." The Commission also has information that Edwardsport did not satisfy any of the Company's promised preconditions to being placed "in-service," either on June 7, 2013 or at any time during the period of June 7, 2013 to March 31, 2014.

ADDITIONAL CONCERNS

Q. Do you have any concerns in addition to Duke's premature "in-service" declaration regarding the current status and future prospects of the Edwardsport Project that, in your opinion, pose significant risks to the Company's retail ratepayers notwithstanding the Settlement approved by the Commission, with certain modifications, in Cause No. 43114-IGCC-4S1?

A. Yes, I have three such additional concerns. In particular, I am concerned that:

(1) Duke's retail customers will be charged excessive rates for Edwardsport's generation given the plant's performance and costs to date;

(2) Duke is claiming certain repair and related costs as Operating and Maintenance (O&M) expenses for purposes of retail rate recovery which, under the Settlement, should be classified as Construction Costs subject to the Hard Cost Cap; and

(3) Duke's retail customers will be asked to bear the risks and costs associated with Edwardsport's CO_2 emissions being significantly in excess of those projected by the Company during the plant's CPCN proceedings.

<u>Excessive Rates in Relation to Plant Performance and Costs to Date</u>

Q. Please explain your concern that Duke's retail customers will be charged excessive rates for Edwardsport's generation given the plant's performance and costs to whatever date the Commission determines the plant actually achieves commercial operation.

A. This concern has three components: (1) capital costs; (2) fuel-related costs; and (3) O&M costs other than fuel-related costs.

<u>Capital Costs</u>

Under the Settlement, the Settling Parties agreed:

> Other than as set forth in this Settlement, the Non-Duke Settling Parties agree that they will seek no further rate or regulatory "penalties" relative to the construction and overall final Construction Costs of the Project (plus AFUDC as allowed above); however, the non-Duke Settling Parties shall retain all rights under Indiana law to make arguments and seek relief concerning post-in-service operating performance of the Project.

I am advised by counsel that this provision is not binding on Joint Intervenors or on the Commission -- only on the Non-Duke Settling Parties. I am further advised that the language after the semi-colon expressly and plainly gives even those parties "all rights under Indiana law to make arguments and seek relief concerning post-in-service operating performance of the Project."

As my earlier testimony plainly shows, the performance of Edwardsport in generating power since Duke declared the plant to be in commercial operation as of June 7, 2013 has fallen woefully short of that on which the economics underlying its CPCN as most recently modified by the Commission were based. In particular:

- Edwardsport's actual net generation for the period June 2013 through March 2014, part of the IGCC-12 and 13 review periods included within the scope of this proceeding, was only 45 percent of the net generation that the Company had forecasted for this period in December 2012.
- Edwardsport's actual net generation for the period June 2013 through July 2014 was only 59 percent of the net generation forecasted by Duke for this period in December 2012.

Under these circumstances, my professional opinion is that it is and will continue to be grossly inequitable for Duke's retail ratepayers to be charged 100% of the capital costs (i.e. return plus depreciation) approved in Cause No. 43114-IGCC-4S1 for Edwardsport. Accordingly, it is my recommendation that the Commission discount those costs charged to ratepayers to reflect actual generating performance during the period of actual commercial operation.

For example, if the Commission – notwithstanding my unequivocal opinion to the contrary – were to determine that Edwardsport was in commercial operation as of June 7, 2013, then the capital costs included in the retail revenue requirement for IGCC-12 and 13 for the period June 7, 2013 through March 31, 2014 should only be 45% of those claimed by the Company. Of course, the discounting percentage would vary for a later "in-service" date determined by the Commission based on the plant's generating performance between that date and March 31, 2014.

Fuel-Related Costs

I am advised by counsel that fuel-related costs for Edwardsport are recovered by Duke in its FAC and not in its IGCC proceedings, including the current IGCC-12 and 13 consolidated proceeding. In addition, I am advised that the FAC proceeding initiated by the Commission in Cause No. 38707-FAC-99-S1 to determine the implications of the Commission's findings and conclusions in the current consolidated IGCC proceeding has been stayed pending the outcome of this proceeding. Accordingly, I will defer my testimony regarding those implications until such time, except to state here that whatever actual "in-service" date the Commission would determine for Edwardsport in this proceeding, it would definitely have implications for the proper amounts of fuel-related cost recovery in Duke's FAC proceedings covering time periods after June 7, 2013.

O&M Costs Other Than Fuel-Related Costs

I am advised by counsel that O&M costs other than fuel-related costs for Edwardsport are recovered by Duke in its IGCC proceedings, including the current IGCC-12 and 13 consolidated proceeding. Accordingly, my professional opinion is that it is and will continue to be grossly inequitable for Duke's retail ratepayers to be charged 100% of the O&M costs claimed by the Company for Edwardsport in this proceeding. Accordingly, it is my recommendation that the Commission discount those costs charged to ratepayers to reflect projections the Company made during Cause No. 43114-IGCC-4S1 on which the Settlement and

Order in that Cause were premised. The testimony of Joint Intervenors' witness Smith reflects the analyses and calculations required to implement this recommendation.

My recommendation is based on principles of fundamental fairness and regulatory accountability. Certificate of Public Convenience and Necessity (CPCN) proceedings such as IGCC-4S1 are, among other purposes, intended to assure that monopoly utilities are permitted only to construct major generating facilities, such as Edwardsport, for which their captive customers will be charged only when they are demonstrated by substantial evidence to be the lowest reasonable cost resource option available to match reliable predictions of future supply and demand. If a utility is permitted to charge its customers for construction and/or operating costs materially higher than those it projected for a major plant like Edwardsport during its Certificate of Need proceedings, the result amounts to a "bait and switch" for customers and a perverse incentive for utilities.

Accordingly, I believe it is critical for regulators to hold utilities accountable for their promises and predictions of performance and cost made for major plants such as Edwardsport in their CPCN proceedings. I believe that such a result is especially critical here where Edwardsport's performance is so much poorer and it costs so much higher than the Company projected and where the Commission approved and re-approved the plant.

Improperly Classified O&M Expenses

Q. Please explain your concern that Duke is claiming certain repair and related costs as Operating and Maintenance (O&M) expenses for purposes of retail rate recovery which, under the Settlement, should be classified as Construction Costs subject to the Hard Cost Cap.

A. Section 2.E of the Settlement approved by the Commission in Cause No. 43114-IGCC-4S1 with modifications not relevant here states:

E. "Construction Costs" of the Project shall be defined in accordance with usual utility practices and in accordance with FERC guidelines and includes all costs required to achieve "final completion," as that term is defined in the December 20, 2007 contract between Duke Energy Indiana and GE (see Attachment A), such as engineering, materials, construction and equipment purchases, capitalized AFUDC (through June 30, 2012), and all start-up and testing, validation and commissioning costs, and costs of repairs and modifications identified during start-up, testing, validation and commissioning and all such costs required whether actually disbursed or only obligated during such period, as well as any costs subsequently incurred to pay claims disallowed or unpaid during such period; except that: "Construction Costs" of the Project and the Hard Cost Cap shall not include normal operating and maintenance ("O&M") expenditures on the Project, which, according to FERC guidelines, begin after the "InService Operational Date" and shall not include subsequent ongoing capital spent on the Project for normal capitalized repairs or maintenance expenditures or additional plant and equipment necessary for the continued operation of the Project after the "In-Service Operational Date", unless identified during start-up, testing, validation and commissioning as being necessary to reach "final completion", nor does the cap apply to orders of the Commission approving cost recovery related to carbon capture and storage (including study costs) involving the Project.

In this context, I am concerned that substantial costs claimed by the Company as operating and maintenance expenses should have been classified as "construction costs" under the Settlement because, as a factual matter, they were incurred for "repairs and modifications identified during start-up, testing, validation and commissioning as being necessary to reach 'final completion.'"

Mr. Smith will explain the accounting aspects of this matter in his testimony, but the technical aspects are my responsibility. Specifically, my review of Mr. Stultz's prefiled testimony from page 10 line 5 through page 16 line 3 in IGCC-12 and from page 3 line 3 through page 11 line 21 and page 19 line 4 through page 21 line 9 in IGCC-13, as well as the Company's responses to related discovery requests in Joint Intervenors' Discovery Request Sets 6, 10, 13, 17, 22 and 25 indicate that there are important categories of costs claimed by the Company to be recoverable from ratepayers as incurred for normal capitalized repairs and expensed maintenance activities "necessary for the continued operation of the Project after the 'InService Operational Date'" which were, in fact, incurred for "repairs and modifications identified during start-up, testing, validation and commissioning as being necessary to reach 'final completion.'"

These important categories of costs include at least the following:

(1) Costs for "repairs and modifications identified . . . as being necessary to reach 'final completion'" which the Company claims were identified during a time period on and after June 7, 2013 which the Company considered to be a period of "commercial operation" which should have been considered a period of further "testing" within the meaning of the Settlement;

(2) Costs incurred on and after June 7, 2013 for "repairs and modifications identified during start-up, testing, validation and commissioning" prior to June 7, 2013 "as being necessary to reach 'final completion'" which the Company has nonetheless expensed currently since June 7, 2013.

The first category of improperly classified O&M expenses is, of course, inherent in the dispute between the Company and other parties regarding whether the period from June 7, 2013 through March 31, 2014 (or even later) should be considered a period of "commercial operation" or a period of further "testing" for Edwardsport. But, it is important to recognize that the implications of this dispute extend beyond the reclassification of all costs incurred before the appropriate "In Service Operation Date" to some costs incurred after that date. It is undisputed that, even assuming without conceding that the "In Service Operation Date" under the Settlement is June 7, 2013, there were "startup" and "testing" activities within the meaning of those terms under the Settlement which took place through at least

May 2014 and perhaps as late as November 2014.[45] Accordingly, "repairs and modifications required for Final Completion" identified during those post-June 7, 2013 "startup" and "testing" activities should be classified as "Construction Costs" under the Settlement.

The other category of improperly classified O&M expenses arises out of the manner in which repair and modification costs to address equipment problems and technical issues identified prior to June 7, 2013, are being reviewed and some are being classified as "Construction Costs" by the Company. Duke witness Stultz testified in both IGCC-12 (page 12, lines 18 to 21) and IGCC-13 (page 21, lines 4 to 9) that a team of Company employees meets on a regular basis "to review the maintenance needs of the Plant with an eye towards ensuring that no expenses are presented for recovery in this proceeding (or any other) that would contravene the Commission's Order in Cause No. 43114 IGCC 4S1." However, Joint Intervenors' follow up discovery shows that that this review team is not reviewing all or even most of the maintenance activities and associated work orders initiated at the Plant, but only a comparatively limited number of requests for capital expenditures and then those comparatively few requests are screened against a pre-determined "short list" of narrowly defined categories of repairs and modifications which the Company has unilaterally decided meet the criteria set out in Section 2.E of the Settlement.

Joint Intervenors have experienced significant difficulty in obtaining the documentation from the Company necessary to identify and quantify the second and third categories of improperly classified O&M expenses. Indeed, most of the relevant information has been obtained only through follow up discovery requests and responses after the Commission granted Joint Intervenors' Motion to Compel involving initial requests included in Discovery Request Sets 6 and 10. But, there

45 See Duke Response and 8-11-14 Supplemental Response to DEI-IG DR1.4

can be no question that these misclassified costs exist and are significant in amount.

For instance, Duke itself stated in a high-level communication from Mr. Thompson to Mr. Sundstrom at GE on November 8, 2013 (Duke Numbered Letter No. 1116, page 3 of 7) that a significant design issue attributable to GE was the cause of slagging occasioning frequent corrective maintenance activities and related O&M costs for Duke:

[redacted]

Moreover, there are numerous maintenance work orders the costs of which are included in the O&M costs which the Company is seeking to recover in IGCC-12 and 13 which are at least arguably and, in some cases, even indisputably traceable to design and construction issues identified as requiring correction prior to the Company's "in-service" declaration of June 7, 2013, which the Company is not considering, especially but not exclusively in the gasification and grey water processes of the Plant. Finally, it appears from my review that the Company is considering repairs and modifications directly related to correcting certain design and construction issues which it has correctly identified as meeting the criteria for classifying their costs as "Construction Costs" under the Settlement (e.g. HeatTrace/FreezeProtection, Liquid Nitrogen Pumps and Supply), but is not so classifying the consequential costs of repairs and/or modifications to other equipment and/or processes which were adversely affected by a "cascade effect" resulting from the underlying technical issues and equipment problems.

Carbon Dioxide Emissions

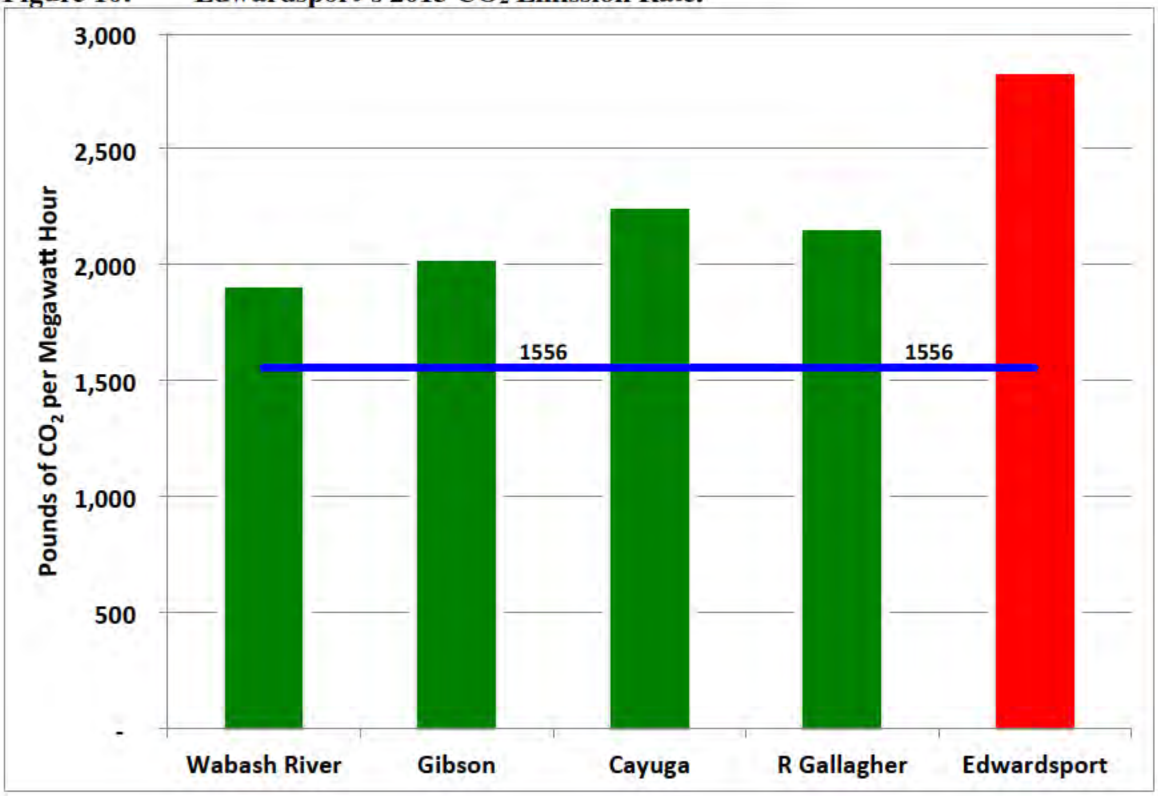
Q. How have Edwardsport's actual Carbon Dioxide (CO_2) emissions compared to what the Company told the Commission they would be?

A. The Company originally projected that Edwardsport would emit, on average 1,556 pounds per MWH of CO_2 from Edwardsport.[46] However, as shown in Figures 10 and 11, below, Edwardsport's actual CO_2 emissions during 2013 and the first nine months of 2014 were substantially higher than what Duke promised the Commission could be achieved back in 2007. Please note that the promised CO_2 emission rate only reflected what Duke thought the IGCC technology could achieve—it did not include carbon capture and sequestration.

---

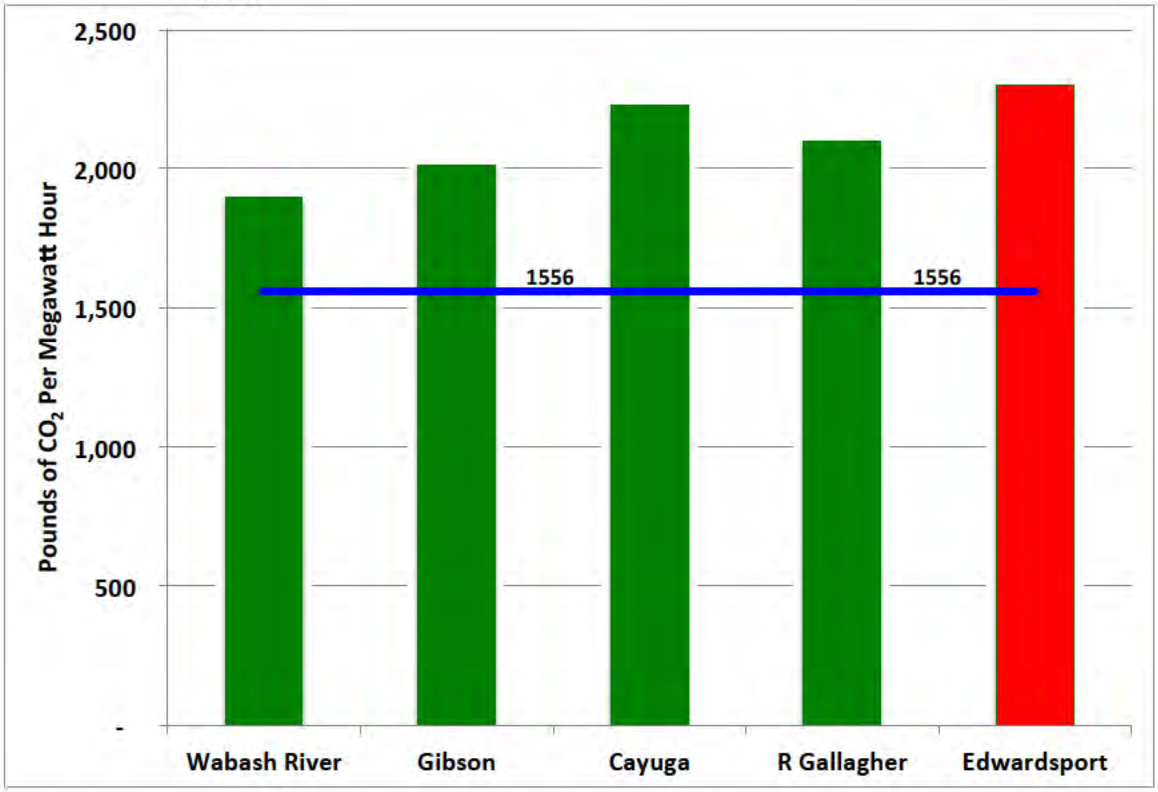
46 Cause No. 43114, Petitioner's Exhibit 17-B.

Figure 10: Edwardsport's 2013 CO_2 Emission Rate.[47]



[47] Wabash River, Gibson, Cayuga, R Gallagher emission rates are for all of 2013. The Edwardsport emission rate begins at the date which Duke declared Edwardsport "in service", i.e. June 7, 2013. Source: SNL Financial.

Figure 11: Edwardsport's CO_2 Emission Rate – January through September 2014.[48]



As can be seen in Figures 10 and 11, Edwardsport's CO_2 emission rate was higher than that of the Company's four other coal plants.

Q. What is the significance of these higher than projected CO_2 emissions?

A. As explained more fully in the prefiled testimony of Joint Intervenors' witness Kanfer, Edwardsport's higher than projected CO_2 emissions will make it more difficult for the Company and the state to comply with the EPA's proposed Section 111(d) regulations when they become final. In addition, these emissions will make the plant more expensive for ratepayers when an actual carbon price is placed on the CO_2 emitted by Edwardsport. As such, these increased emissions are a foreseeable future risk for Duke's ratepayers because Edwardsport will be

[48] Sources: U.S. EPA's CEMS database and SNL Financial.

classified as a major source of CO_2 emissions under whatever regulatory regime is adopted in the future for those emissions and will be subject to that regime because it is projected to have a future operating life of over 30 years.

Q. Do you have a recommendation as to how the Commission should address these implications of the Plant's higher than projected CO_2 emissions?

A. Yes. The Commission should adopt a performance standard that requires that the Company, not ratepayers bear all costs resulting from the plant's failure to achieve and maintain on an ongoing basis during its period of commercial operation the CO_2 emissions rate projected during its CPCN proceedings.

Q. Does this complete your testimony at this time?

A. Yes.

VERIFICATION

I, David A. Schlissel, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

David A. Schlissel   December 15, 2014

David A. Schlissel   Date

EXHIBIT DAS-1

David A. Schlissel

President
Schlissel Technical Consulting, Inc.
45 Horace Road, Belmont, MA 02478
(617) 489-4840
david@schlissel-technical.com

SUMMARY

I have worked since 1974 as a consultant and attorney on complex management, engineering, and economic issues, primarily in the field of energy. This work has involved conducting technical investigations, preparing economic analyses, presenting expert testimony, providing support during all phases of regulatory proceedings and litigation, and advising clients during settlement negotiations. I received undergraduate and advanced engineering degrees from the Massachusetts Institute of Technology and Stanford University, respectively, and a law degree from Stanford Law School.

PROFESSIONAL EXPERIENCE

Electric Resource Planning - Analyzed the financial and economic costs and benefits of energy supply options. Examined whether there are lower cost, lower risk alternatives than proposed fossil and nuclear power plants. Evaluated the financial, economic and system reliability consequences of retiring existing electric generating facilities. Investigated whether new electric generating facilities are used and useful. Investigated whether new generating facilities that were built for a deregulated subsidiary should be included in the rate base of a regulated utility. Assessed the reasonableness of proposed utility power purchase agreements with deregulated affiliates. Investigated the prudence of utility power purchases in deregulated markets.

Coal-fired Generation – Evaluated the economic and financial risks of investing in, constructing and operating new coal-fired power plants. Analyzed the economic and financial risks of making expensive environmental and other upgrades to existing plants. Investigated whether plant owners had adequately considered the risks associated with building new fossil-fired power plants, the most significant of which are the likelihood of federal regulation of greenhouse gas emissions and construction cost increases.

Power Plant Air Emissions – Investigated whether proposed generating facilities would provide environmental benefits in terms of reduced emissions of NO_x, SO_2 and CO_2. Examined whether new state and federal emission standards would lead to the retirement of existing power plants or otherwise have an adverse impact on electric system reliability.

Power Plant Water Use – Examined power plant repowering as a strategy for reducing water consumption at existing electric generating facilities. Analyzed the impact of converting power plants from once-through to closed-loop systems with cooling towers on plant revenues and electric system reliability. Evaluated the potential impact of the EPA's Proposed Clean Water Act Section 316(b) Rule for Cooling Water Intake Structures at existing power plants.

Electric System Reliability - Evaluated whether existing or new generation facilities and transmission lines are needed to ensure adequate levels of system reliability. Investigated the causes of distribution system outages and inadequate service reliability. Examined the reasonableness of utility system reliability expenditures.

Power Plant Repowering - Evaluated the environmental, economic and reliability impacts of rebuilding older, inefficient generating facilities with new combined cycle technology.

Power Plant Operations and Economics - Investigated the causes of more than one hundred power plant and system outages, equipment failures, and component degradation, determined whether these problems could have been anticipated and avoided, and assessed liability for repair and replacement costs. Examined power plant operating, maintenance, and capital costs. Evaluated utility plans for and management of the replacement of major power plant components. Assessed the adequacy of power plant quality assurance and maintenance programs. Examined the selection and supervision of contractors and subcontractors.

Nuclear Power – Reviewed recent cost estimates for proposed nuclear power plants. Examined the impact of the nuclear power plant life extensions and power uprates on decommissioning costs and collections policies. Examined the reasonableness of utility decisions to sell nuclear power assets and evaluated the value received as a result of the auctioning of those plants. Investigated the significance of the increasing ownership of nuclear power plants by multiple tiered holding companies with limited liability company subsidiaries. Investigated the potential safety consequences of nuclear power plant structure, system, and component failures.

Transmission Line Siting – Examined the need for proposed transmission lines. Analyzed whether proposed transmission lines could be installed underground. Worked with clients to develop alternate routings for proposed lines that would have reduced impacts on the environment and communities.

Electric Industry Regulation and Markets - Examined whether generating facilities experienced more outages following the transition to a deregulated wholesale market in New England. Evaluated the reasonableness of nuclear and fossil plant sales, auctions, and power purchase agreements. Analyzed the impact of proposed utility mergers on market power. Assessed the reasonableness of contract provisions and terms in proposed power supply agreements.

Expert Testimony - Presented the results of management, technical and economic analyses as testimony in more than 100 proceedings before regulatory boards and commissions in 35 states, before two federal regulatory agencies, and in state and federal court proceedings.

Litigation and Regulatory Support - Participated in all aspects of the development and preparation of case presentations on complex management, technical, and economic issues. Assisted in the preparation and conduct of pre-trial discovery and depositions. Helped identify and prepare expert witnesses. Aided the preparation of pre-hearing petitions and motions and post-hearing briefs and appeals. Assisted counsel in preparing for hearings and oral arguments. Advised counsel during settlement negotiations.

TESTIMONY, AFFIDAVITS, DEPOSITIONS AND COMMENTS

Public Service Commission of West Virginia (Case No. 12-1655-E-PC) – June 2013
The reasonableness of Appalachian Power Company's proposed acquisition of 2/3 of Unit 3 of the John E. Amos power plant and ½ of the two unit Mitchell power plant.

Public Service Commission of West Virginia (Case No. 12-1571-E-PC) – April 2013
The reasonableness of Monogahela Power Company's proposed acquisition of 80 percent of the Harrison Power Station.

Virginia State Corporation Commission (Case No. PUE-2012-00128) – March 2013
Whether Dominion Virginia Power's proposed Brunswick Project natural gas-fired combined cycle power plant is needed and in the public interest.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 8) – June 2012
Startup and pre-operational testing delays at Duke Energy Indiana's Edwardsport IGCC Project.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – March 2012
Petition to Reopen the docket for the Kemper County IGCC Plant based on changed circumstances.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – February 2012
The financial and economic risks of retrofitting Mississippi Power Company's Plant Daniel Coal Plant.

Georgia Public Service Commission (Docket No. 34218) – November 2011
The reasonableness of Georgia Power Company's proposed fossil plant decertification/retirement plan.

Maryland Public Service Commission (Case No. 9271) – October 2011
The reasonableness of Constellation Energy Group's proposed divestiture of three coal-fired power plants as mitigation for market power concerns arising from its proposed merger with Exelon Corporation.

Minnesota Public Utilities Commission (Docket No. E017/M-10-1082) – August and September 2011
Whether the proposed addition of the Big Stone Plant Air Quality Control System is a lower cost alternative for the ratepayers of Otter Tail Power Company than retirement of the Plant and replacement by a natural gas-fired combined cycle unit possibly combined with new wind capacity.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – June, July, and October 2011 and June 2012
Duke Energy Indiana's imprudence and gross mismanagement of Edwardsport IGCC Project.

Kansas State Corporation Commission (Docket No. 11-KCPE-581-PRE) – June 2011
The reasonableness of the proposed environmental upgrades at the La Cygne Generating Station Units 1 and 2.

Arizona Corporation Commission (Docket No. E-01345A-10-0474) – May 2011
The reasonableness of Arizona Public Service Company's proposed acquisition of Southern California Edison's share of Four Corners Units 4 and 5.

Public Utility Commission of Colorado (Docket No. 10M-245E) – September, October and November 2010
The reasonableness of Public Service of Colorado's proposed Emissions Reduction Plan.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 4S1) – July, November and December 2010
The reasonableness of Duke Energy Indiana's new analyses of the economics of completing the Edwardsport Project as an IGCC plant.

Oregon Public Utility Commission (Docket LC 48) – May and August 2010
Comments and Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan.

South Dakota Public Service Commission (Docket No. EL-09-018) – April 2010
The reasonableness of Black Hills Power Company's 2007 Integrated Resource Plan and the Company's decision to build the Wygen III coal-fired power plant.

Michigan Public Service Commission (Docket No. U-16077) – April 2010
Comments on the City of Holland Board of Public Works' 2010 Power Supply Study.

Illinois Commerce Commission (Tenaska Clean Coal Facility Analysis) – April 2010
Comments on the Facility Cost Report for the proposed Taylorville IGCC power plant.

North Carolina Utilities Commission (Docket No. E-100, Sub 124) – February 2010
The reasonableness of the 2009 Integrated Resource Plans of Duke Energy Carolinas and Progress Energy Carolinas.

Mississippi Public Service Commission (Docket No. 2009-UA-014) – December 2009
The costs and risks associated with the proposed Kemper County IGCC power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-137) –December 2009 and January 2010
The costs and risks associated with the proposed installation of emissions control equipment at the Edgewater Unit 5 coal-fired power plant.

Public Service Commission of Wisconsin (Docket No. 05-CE-138) –September and October 2009
The costs and risks associated with the proposed installation of emissions control equipment at the Columbia 1 and 2 coal-fired power plants.

Public Service Commission of Michigan (Docket No. U-15996) – July 2009
Comments on Consumer Energy's Electric Generation Alernatives Analysis for the Balanced Energy Initiative including the Proposed Karn-Weadock Coal Plant.

Public Service Commission of Michigan (Docket No. U-16000) – Juy 2009
Comments on Wolverine Power Cooperative's Electric Generation Alternatives Analysis for the Proposed Rogers City Coal Plant.

Georgia Public Service Commission (Docket No. 27800-U) – December 2008
The possible costs and risks of proceeding with the proposed Plant Vogtle Units 3 and 4 nuclear power plants.

Public Service Commission of Wisconsin (Docket No. 6680-CE-170) – August and Sepember 2008
The risks associated with the proposed Nelson Dewey 3 baseload coal-fired power plant.

Indiana Utility Regulatory Commission (Cause No. 43114 IGCC 1) – July 2008
The estimated cost of Duke Energy Indiana's Edwardsport Project.

Public Service Commission of Maryland (Case 9127) – July 2008
The estimated cost of the proposed Calvert Cliffs Unit 3 nuclear power plant.

Ohio Power Siting Board (Case No. 06-1358-EL-BGN) – December 2007
AMP-Ohio's application for a Certificate of Environmental Compatibility and Public Need for a 960 MW pulverized coal generating facility.

U.S. Nuclear Regulatory Commission (Docket Nos. 50-247-LR, 50-286-LR) – November 2007 and February 2009
The available options for replacing the power generated at Indian Point Unit 2 and/or Unit 3.

West Virginia Public Service Commission (Case No. 06-0033-E-CN) – November 2007
Appalachian Power Company's application for a Certificate of Public Convenience and Necessity for a 600 MW integrated gasification combined cycle generating facility.

Iowa Utility Board (Docket No. GCU-07-01) – October 2007
Whether Interstate Power & Light Company's adequately considered the risks associated with building a new coal-fired power plant and whether that Company's participation in the proposed Marshalltown plant is prudent.

Virginia State Corporation Commission (Case No. PUE-2007-00066) – November 2007
Whether Dominion Virginia Power's adequately considered the risks associated with building the proposed Wise County coal-fired power plant and whether that Commission should grant a certificate of public convenience and necessity for the plant.

Louisiana Public Service Commission (Docket No. U-30192) – September 2007
The reasonableness of Entergy Louisiana's proposal to repower the Little Gypsy Unit 3 generating facility as a coal-fired power plant.

Arkansas Public Service Commission (Docket No. 06-154-U) – July 2007
The probable economic impact of the Southwestern Electric Power Company's proposed Hempstead coal-fired power plant project.

North Dakota Public Service Commission (Case Nos. PU-06-481 and 482) – May 2007 and April 2008
Whether the participation of Otter Tail Power Company and Montana-Dakota Utilities in the Big Stone II Generating Project is prudent.

Indiana Utility Regulatory Commission (Cause No. 43114) – May 2007
The appropriate carbon dioxide ("CO_2") emissions prices that should be used to analyze the relative economic costs and benefits of Duke Energy Indiana and Vectren Energy Delivery of Indiana's proposed Integrated Gasification Combined Cycle Facility and whether Duke and Vectren have appropriately reflected the capital cost of the proposed facility in their modeling analyses.

Public Service Commission of Wisconsin (Docket No. 6630-EI-113) – May and June 2007
Whether the proposed sale of the Point Beach Nuclear Plant to FPL Energy Point Beach, LLC, is in the interest of the ratepayers of Wisconsin Electric Power Company.

Florida Public Service Commission (Docket No. 070098-EI) – March 2007
Florida Light & Power Company's need for and the economics of the proposed Glades Power Park.

Michigan Public Service Commission (Case No. 14992-U) – December 2006
The reasonableness of the proposed sale of the Palisades Nuclear Power Plant.

Minnesota Public Utilities Commission (Docket No. CN-05-619) – November 2006, December 2007, January 2008 and November 2008
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the facility; and whether the proposed project is a lower cost alternative than renewable options, conservation and load management.

North Carolina Utilities Commission (Docket No. E-7, Sub 790) – September 2006 and January 2007
Duke's need for two new 800 MW coal-fired generating units and the relative economics of adding these facilities as compared to other available options including energy efficiency and renewable technologies.

New Mexico Public Regulatory Commission (Case No. 05-00275-UT) – September 2006
Report to the New Mexico Commission on whether the settlement value of the adjustment for moving the 141 MW Afton combustion turbine merchant plant into rate base is reasonable.

Arizona Corporation Commission (Docket No. E-01345A-0816) – August and September 2006
Whether APS's acquisition of the Sundance Generating Station was prudent and the reasonableness of the amounts that APS requested for fossil plant O&M.

U.S. District Court for the District of Montana (Billings Generation, Inc. vs. Electrical Controls, Inc, et al., CV-04-123-BLG-RFC) – August 2006
Quantification of plaintiff's business losses during an extended power plant outage and plaintiff's business earnings due to the shortening and delay of future plant outages. [Confidential Expert Report]

Deposition in South Dakota Public Utility Commission Case No. EL05-022 – June 14, 2006

South Dakota Public Utility Commission (Case No. EL05-022) – May and June 2006
Whether the co-owners of the proposed Big Stone II coal-fired generating plant have appropriately reflected the potential for the regulation of greenhouse gases in their analyses of the alternatives to the proposed facility; the need and timing for new supply options in the co-owners' service territories; and whether there are alternatives to the proposed facility that are technically feasible and economically cost-effective.

Georgia Public Service Commission (Docket No. 22449-U) – May 2006
Georgia Power Company's request for an accounting order to record early site permitting and construction operating license costs for new nuclear power plants.

California Public Utilities Commission (Dockets Nos. A.05-11-008 and A.05-11-009) – April 2006
The estimated costs for decommissioning the Diablo Canyon, SONGS 2&3 and Palo Verde nuclear power plants and the annual contributions that are needed from ratepayers to assure that adequate funds will be available to decommission these plants at the projected ends of their service lives.

New Jersey Board of Public Utilities (Docket No. EM05020106) – November and December 2005 and March 2006
Joint Testimony with Bob Fagan and Bruce Biewald on the market power implications of the proposed merger between Exelon Corp. and Public Service Enterprise Group.

Virginia State Corporation Commission (Case No. PUE-2005-00018)– November 2005
The siting of a proposed 230 kV transmission line.

Iowa Utility Board (Docket No. SPU-05-15) – September and October 2005
The reasonableness of IPL's proposed sale of the Duane Arnold Energy Center nuclear plant.

New York State Department of Environmental Conservation (DEC #3-3346-00011/00002) – October 2005
The likely profits that Dynegy will earn from the sale of the energy and capacity of the Danskammer Generating Facility if the plant is converted from once-through to closed-cycle cooling with wet towers or to dry cooling.

Arkansas Public Service Commission (Docket 05-042-U) – July and August 2005
Arkansas Electric Cooperative Corporation's proposed purchase of the Wrightsville Power Facility.

Maine Public Utilities Commission (Docket No. 2005-17) – July 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Eastern Maine Electric Cooperative's request for a CPCN to purchase 15 MW of transmission capacity from New Brunswick Power.

Federal Energy Regulatory Commission (Docket No. EC05-43-0000) – April and May 2005
Joint Affidavit and Supplemental Affidavit with Bruce Biewald on the market power aspects of the proposed merger of Exelon Corporation and Public Service Enterprise Group, Inc.

Maine Public Utilities Commission (Docket No. 2004-538 Phase II) – April 2005
Joint testimony with Peter Lanzalotta and Bob Fagan evaluating Maine Public Service Company's request for a CPCN to purchase 35 MW of transmission capacity from New Brunswick Power.

Maine Public Utilities Commission (Docket No. 2004-771) – March 2005
Analysis of Bangor Hydro-Electric's Petition for a Certificate of Public Convenience and Necessity to construct a 345 kV transmission line

United States District Court for the Southern District of Ohio, Eastern Division (Consolidated Civil Actions Nos. C2-99-1182 and C2-99-1250)
Whether the public release of company documents more than three years old would cause competitive harm to the American Electric Power Company. [Confidential Expert Report]

New Jersey Board of Public Utilities (Docket No. EO03121014) – February 2005
Whether the Board of Public Utilities can halt further collections from Jersey Central Power & Light Company's ratepayers because there already are adequate funds in the company's decommissioning trusts for the Three Mile Island Unit No. 2 Nuclear Plant to allow for the decommissioning of that unit without endangered the public health and safety.

Maine Public Utilities Commission (Docket No. 2004-538) – January and March 2005
Analysis of Maine Public Service Company's request to construct a 138 kV transmission line from Limestone, Maine to the Canadian Border.

California Public Utilities Commission (Application No. AO4-02-026) – December 2004 and January 2005
Southern California Edison's proposed replacement of the steam generators at the San Onofre Unit 2 and Unit 3 nuclear power plants and whether the utility was imprudent for failing to initiate litigation against Combustion Engineering due to defects in the design of and materials used in those steam generators.

United States District Court for the Southern District of Indiana, Indianapolis Division (Civil Action No. IP99-1693) – December 2004
Whether the public release of company documents more than three years old would cause competitive harm to the Cinergy Corporation. [Confidential Expert Report]

California Public Utilities Commission (Application No. AO4-01-009) – August 2004
Pacific Gas & Electric's proposed replacement of the steam generators at the Diablo Canyon nuclear power plant and whether the utility was imprudent for failing to initiate litigation against Westinghouse due to defects in the design of and materials used in those steam generators.

Public Service Commission of Wisconsin (Docket No. 6690-CE-187) – June, July and August 2004
Whether Wisconsin Public Service Corporation's request for approval to build a proposed 515 MW coal-burning generating facility should be granted.

Public Service Commission of Wisconsin (Docket No. 05-EI-136) – May and June 2004
Whether the proposed sale of the Kewaunee Nuclear Power Plant to a subsidiary of an out-of-state holding company is in the public interest.

Connecticut Siting Council (Docket No. 272) – May 2004
Whether there are technically viable alternatives to the proposed 345-kV transmission line between Middletown and Norwalk Connecticut and the length of the line that can be installed underground.

Arizona Corporation Commission (Docket No. E-01345A-03-0437 – February 2004
Whether Arizona Public Service Company should be allowed to acquire and include in rate base five generating units that were built by a deregulated affiliate.

State of Rhode Island Energy Facilities Siting Board (Docket No. SB-2003-1) – February 2004
Whether the cost of undergrounding a relocated 115kV transmission line would be eligible for regional cost socialization.

State of Maine Department of Environmental Protection (Docket No. A-82-75-0-X) – December 2003
The storage of irradiated nuclear fuel in an Independent Spent Fuel Storage Installation (ISFSI) and whether such an installation represents an air pollution control facility.

Rhode Island Public Utility Commission (Docket No. 3564) – December 2003 and January 2004
Whether Narragansett Electric Company should be required to install a relocated 115kV transmission line underground.

New York State Board on Electric Generation Siting and the Environment (Case No. 01-F-1276) – September, October and November 2003
The environmental, economic and system reliability benefits that can reasonably be expected from the proposed 1,100 MW TransGas Energy generating facility in Brooklyn, New York.

Wisconsin Public Service Commission (Case 6690-UR-115) - September and October 2003
The reasonableness of Wisconsin Public Service Corporation's decommissioning cost collections for the Kewaunee Nuclear Plant.

Oklahoma Corporation Commission (Cause No. 2003-121) – July 2003
Whether Empire District Electric Company properly reduced its capital costs to reflect the write-off of a portion of the cost of building a new electric generating facility.

Arkansas Public Service Commission (Docket 02-248-U) – May 2003
Entergy's proposed replacement of the steam generators and the reactor vessel head at the ANO Unit 1 Steam Generating Station.

Appellate Tax Board, State of Massachusetts (Docket No C258405-406) – May 2003
The physical nature of electricity and whether electricity is a tangible product or a service.

Maine Public Utilities Commission (Docket 2002-665-U) – April 2003
Analysis of Central Maine Power Company's proposed transmission line for Southern York County and recommendation of alternatives.

Massachusetts Legislature, Joint Committees on Government Regulations and Energy – March 2003
Whether PG&E can decide to permanently retire one or more of the generating units at its Salem Harbor Station if it is not granted an extension beyond October 2004 to reduce the emissions from the Station's three coal-fired units and one oil-fired unit.

New Jersey Board of Public Utilities (Docket No. ER02080614) – January 2003
The prudence of Rockland Electric Company's power purchases during the period August 1, 1999 through July 31, 2002.

New York State Board on Electric Generation Siting and the Environment (Case No. 00-F-1356) – September and October 2002 and January 2003
The need for and the environmental benefits from the proposed 300 MW Kings Park Energy generating facility.

Arizona Corporation Commission (Docket No. E-01345A-01-0822) – May 2002
The reasonableness of Arizona Public Service Company's proposed long-term power purchase agreement with an affiliated company.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) – March 2002
Repowering NYPA's existing Poletti Station in Queens, New York.

Connecticut Siting Council (Docket No. 217) – March 2002, November 2002, and January 2003
Whether the proposed 345-kV transmission line between Plumtree and Norwalk substations in Southwestern Connecticut is needed and will produce public benefits.

Vermont Public Service Board (Case No. 6545) – January 2002
Whether the proposed sale of the Vermont Yankee Nuclear Plant to Entergy is in the public interest of the State of Vermont and Vermont ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12RE02) – December 2001
The reasonableness of adjustments that Connecticut Light and Power Company seeks to make to the proceeds that it received from the sale of Millstone Nuclear Power Station.

Connecticut Siting Council (Docket No. 208) – October 2001
Whether the proposed cross-sound cable between Connecticut and Long Island is needed and will produce public benefits for Connecticut consumers.

New Jersey Board of Public Utilities (Docket No. EM01050308) - September 2001
The market power implications of the proposed merger between Conectiv and Pepco.

Illinois Commerce Commission Docket No. 01-0423 – August, September, and October 2001
Commonwealth Edison Company's management of its distribution and transmission systems.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1627) - August and September 2001
The environmental benefits from the proposed 500 MW NYPA Astoria generating facility.

New York State Board on Electric Generation Siting and the Environment (Case No. 99-F-1191) - June 2001
The environmental benefits from the proposed 1,000 MW Astoria Energy generating facility.

New Jersey Board of Public Utilities (Docket No. EM00110870) - May 2001
The market power implications of the proposed merger between FirstEnergy and GPU Energy.

Connecticut Department of Public Utility Control (Docket 99-09-12RE01) - November 2000
The proposed sale of Millstone Nuclear Station to Dominion Nuclear, Inc.

Illinois Commerce Commission (Docket 00-0361) - August 2000
The impact of nuclear power plant life extensions on Commonwealth Edison Company's decommissioning costs and collections from ratepayers.

Vermont Public Service Board (Docket 6300) - April 2000
Whether the proposed sale of the Vermont Yankee nuclear plant to AmerGen Vermont is in the public interest.

Massachusetts Department of Telecommunications and Energy (Docket 99-107, Phase II) - April and June 2000
The causes of the May 18, 1999, main transformer fire at the Pilgrim generating station.

Connecticut Department of Public Utility Control (Docket 00-01-11) - March and April 2000
The impact of the proposed merger between Northeast Utilities and Con Edison, Inc. on the reliability of the electric service being provided to Connecticut ratepayers.

Connecticut Department of Public Utility Control (Docket 99-09-12) - January 2000
The reasonableness of Northeast Utilities plan for auctioning the Millstone Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-08-01) - November 1999
Generation, Transmission, and Distribution system reliability.

Illinois Commerce Commission (Docket 99-0115) - September 1999
Commonwealth Edison Company's decommissioning cost estimate for the Zion Nuclear Station.

Connecticut Department of Public Utility Control (Docket 99-03-36) - July 1999
Standard offer rates for Connecticut Light & Power Company.

Connecticut Department of Public Utility Control (Docket 99-03-35) - July 1999
Standard offer rates for United Illuminating Company.

Connecticut Department of Public Utility Control (Docket 99-02-05) - April 1999
Connecticut Light & Power Company stranded costs.

Connecticut Department of Public Utility Control (Docket 99-03-04) - April 1999
United Illuminating Company stranded costs.

Maryland Public Service Commission (Docket 8795) - December 1998
Future operating performance of Delmarva Power Company's nuclear units.

Maryland Public Service Commission (Dockets 8794/8804) - December 1998
Baltimore Gas and Electric Company's proposed replacement of the steam generators at the Calvert Cliffs Nuclear Power Plant. Future performance of nuclear units.

Indiana Utility Regulatory Commission (Docket 38702-FAC-40-S1) - November 1998
Whether the ongoing outages of the two units at the D.C. Cook Nuclear Plant were caused or extended by mismanagement.

Arkansas Public Service Commission (Docket 98-065-U) - October 1998
Entergy's proposed replacement of the steam generators at the ANO Unit 2 Steam Generating Station.

Massachusetts Department of Telecommunications and Energy (Docket 97-120) - October 1998
Western Massachusetts Electric Company's Transition Charge. Whether the extended 1996-1998 outages of the three units at the Millstone Nuclear Station were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 98-01-02) - September 1998
Nuclear plant operations, operating and capital costs, and system reliability improvement costs.

Illinois Commerce Commission (Docket 97-0015) - May 1998
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1996 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Service Commission of West Virginia (Case 97-1329-E-CN) - March 1998
The need for a proposed 765 kV transmission line from Wyoming, West Virginia, to Cloverdate, Virginia.

Illinois Commerce Commission (Docket 97-0018) - March 1998
Whether any of the outages of the Clinton Power Station during 1996 were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 97-05-12) - October 1997
The increased costs resulting from the ongoing outages of the three units at the Millstone Nuclear Station.

New Jersey Board of Public Utilities (Docket ER96030257) - August 1996
Replacement power costs during plant outages.

Illinois Commerce Commission (Docket 95-0119) - February 1996
Whether any of the outages of Commonwealth Edison Company's twelve nuclear units during 1994 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses, and program deficiencies could have been avoided or addressed prior to plant outages. Outage-related fuel and replacement power costs.

Public Utility Commission of Texas (Docket 13170) - December 1994
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1991, through December 31, 1993, were caused or extended by mismanagement.

Public Utility Commission of Texas (Docket 12820) - October 1994
Operations and maintenance expenses during outages of the South Texas Nuclear Generating Station.

Wisconsin Public Service Commission (Cases 6630-CE-197 and 6630-CE-209) - September and October 1994
The reasonableness of the projected cost and schedule for the replacement of the steam generators at the Point Beach Nuclear Power Plant. The potential impact of plant aging on future operating costs and performance.

Public Utility Commission of Texas (Docket 12700) - June 1994
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in Unit 3 could be expected to generate cost savings for ratepayers within a reasonable number of years.

Arizona Corporation Commission (Docket U-1551-93-272) - May and June 1994
Southwest Gas Corporation's plastic and steel pipe repair and replacement programs.

Connecticut Department of Public Utility Control (Docket 92-04-15) - March 1994
Northeast Utilities management of the 1992/1993 replacement of the steam generators at Millstone Unit 2.

Connecticut Department of Public Utility Control (Docket 92-10-03) - August 1993
Whether the 1991 outage of Millstone Unit 3 as a result of the corrosion of safety-related plant piping systems was due to mismanagement.

Public Utility Commission of Texas (Docket 11735) - April and July 1993
Whether any of the outages of the Comanche Peak Unit 1 Nuclear Station during the period August 13, 1990, through June 30, 1992, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 91-12-07) - January 1993 and August 1995
Whether the November 6, 1991, pipe rupture at Millstone Unit 2 and the related outages of the Connecticut Yankee and Millstone units were caused or extended by mismanagement. The impact of environmental requirements on power plant design and operation.

Connecticut Department of Public Utility Control (Docket 92-06-05) - September 1992
United Illuminating Company off-system capacity sales. [Confidential Testimony]

Public Utility Commission of Texas (Docket 10894) - August 1992
Whether any of the outages of the River Bend Nuclear Station during the period October 1, 1988, through September 30, 1991, were caused or extended by mismanagement.

Connecticut Department of Public Utility Control (Docket 92-01-05) - August 1992
Whether the July 1991 outage of Millstone Unit 3 due to the fouling of important plant systems by blue mussels was the result of mismanagement.

California Public Utilities Commission (Docket 90-12-018) - November 1991, April 1992, June and July 1993
Whether any of the outages of the three units at the Palo Verde Nuclear Generating Station during 1989 and 1990 were caused or extended by mismanagement. Whether equipment problems, personnel performance weaknesses and program deficiencies could have been avoided or addressed prior to outages. Whether specific plant operating cost and capital expenditures were necessary and prudent.

Public Utility Commission of Texas (Docket 9945) - June 1991
Whether El Paso Electric Company's share of Palo Verde Unit 3 was needed to ensure adequate levels of system reliability. Whether the Company's investment in the unit could be expected to generate cost savings for ratepayers within a reasonable number of years. El Paso Electric Company's management of the planning and licensing of the Arizona Interconnection Project transmission line.

Arizona Corporation Commission (Docket U-1345-90-007) - December 1990 and April 1991
Arizona Public Service Company's management of the planning, construction and operation of the Palo Verde Nuclear Generating Station. The costs resulting from identified instances of mismanagement.

New Jersey Board of Public Utilities (Docket ER89110912J) - July and October 1990
The economic costs and benefits of the early retirement of the Oyster Creek Nuclear Plant. The potential impact of the unit's early retirement on system reliability. The cost and schedule for siting and constructing a replacement natural gas-fired generating plant.

Public Utility Commission of Texas (Docket 9300) - June and July 1990
Texas Utilities management of the design and construction of the Comanche Peak Nuclear Plant. Whether the Company was prudent in repurchasing minority owners' shares of Comanche Peak without examining the costs and benefits of the repurchase for its ratepayers.

Federal Energy Regulatory Commission (Docket EL-88-5-000) - November 1989
Boston Edison's corporate management of the Pilgrim Nuclear Station.

Connecticut Department of Public Utility Control (Docket 89-08-11) - November 1989
United Illuminating Company's off-system capacity sales.

Kansas State Corporation Commission (Case 164,211-U) - April 1989
Whether any of the 127 days of outages of the Wolf Creek generating plant during 1987 and 1988 were the result of mismanagement.

Public Utility Commission of Texas (Docket 8425) - March 1989
Whether Houston Lighting & Power Company's new Limestone Unit 2 generating facility was needed to provide adequate levels of system reliability. Whether the Company's investment in Limestone Unit 2 would provide a net economic benefit for ratepayers.

Illinois Commerce Commission (Dockets 83-0537 and 84-0555) - July 1985 and January 1989
Commonwealth Edison Company's management of quality assurance and quality control activities and the actions of project contractors during construction of the Byron Nuclear Station.

New Mexico Public Service Commission (Case 2146, Part II) - October 1988
The rate consequences of Public Service Company of New Mexico's ownership of Palo Verde Units 1 and 2.

United States District Court for the Eastern District of New York (Case 87-646-JBW) - October 1988
Whether the Long Island Lighting Company withheld important information from the New York State Public Service Commission, the New York State Board on Electric Generating Siting and the Environment, and the U.S. Nuclear Regulatory Commission.

Public Utility Commission of Texas (Docket 6668) - August 1988 and June 1989
Houston Light & Power Company's management of the design and construction of the South Texas Nuclear Project. The impact of safety-related and environmental requirements on plant construction costs and schedule.

Federal Energy Regulatory Commission (Docket ER88-202-000) - June 1988
Whether the turbine generator vibration problems that extended the 1987 outage of the Maine Yankee nuclear plant were caused by mismanagement.

Illinois Commerce Commission (Docket 87-0695) - April 1988
Illinois Power Company's planning for the Clinton Nuclear Station.

North Carolina Utilities Commission (Docket E-2, Sub 537) - February 1988
Carolina Power & Light Company's management of the design and construction of the Harris Nuclear Project. The Company's management of quality assurance and quality control activities. The impact of safety-related and environmental requirements on construction costs and schedule. The cost and schedule consequences of identified instances of mismanagement.

Ohio Public Utilities Commission (Case 87-689-EL-AIR) - October 1987
Whether any of Ohio Edison's share of the Perry Unit 2 generating facility was needed to ensure adequate levels of system reliability. Whether the Company's investment in Perry Unit 1 would produce a net economic benefit for ratepayers.

North Carolina Utilities Commission (Docket E-2, Sub 526) - May 1987
Fuel factor calculations.

New York State Public Service Commission (Case 29484) - May 1987
The planned startup and power ascension testing program for the Nine Mile Point Unit 2 generating facility.

Illinois Commerce Commission (Dockets 86-0043 and 86-0096) - April 1987
The reasonableness of certain terms in a proposed Power Supply Agreement.

Illinois Commerce Commission (Docket 86-0405) - March 1987
The in-service criteria to be used to determine when a new generating facility was capable of providing safe, adequate, reliable and efficient service.

Indiana Public Service Commission (Case 38045) - November 1986
Northern Indiana Public Service Company's planning for the Schaefer Unit 18 generating facility. Whether the capacity from Unit 18 was needed to ensure adequate system reliability. The rate consequences of excess capacity on the Company's system.

Superior Court in Rockingham County, New Hampshire (Case 86E328) - July 1986
The radiation effects of low power testing on the structures, equipment and components in a new nuclear power plant.

New York State Public Service Commission (Case 28124) - April 1986 and June 1987
The terms and provisions in a utility's contract with an equipment supplier. The prudence of the utility's planning for a new generating facility. Expenditures on a canceled generating facility.

Arizona Corporation Commission (Docket U-1345-85) - February 1986
The construction schedule for Palo Verde Unit No. 1. Regulatory and technical factors that would likely affect future plant operating costs.

New York State Public Service Commission (Case 29124) – December 1985 and January 1986
Niagara Mohawk Power Corporation's management of construction of the Nine Mile Point Unit No. 2 nuclear power plant.

New York State Public Service Commission (Case 28252) - October 1985
A performance standard for the Shoreham nuclear power plant.

New York State Public Service Commission (Case 29069) - August 1985
A performance standard for the Nine Mile Point Unit No. 2 nuclear power plant.

Missouri Public Service Commission (Cases ER-85-128 and EO-85-185) - July 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Wolf Creek Nuclear Plant.

Massachusetts Department of Public Utilities (Case 84-152) - January 1985
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

Maine Public Utilities Commission (Docket 84-113) - September 1984
The impact of safety-related regulatory requirements and plant aging on power plant operating costs and performance. Regulatory factors and plant-specific design features that will likely affect the future operating costs and performance of the Seabrook Nuclear Plant.

South Carolina Public Service Commission (Case 84-122-E) - August 1984
The repair and replacement strategy adopted by Carolina Power & Light Company in response to pipe cracking at the Brunswick Nuclear Station. Quantification of replacement power costs attributable to identified instances of mismanagement.

Vermont Public Service Board (Case 4865) - May 1984
The repair and replacement strategy adopted by management in response to pipe cracking at the Vermont Yankee nuclear plant.

New York State Public Service Commission (Case 28347) -January 1984
The information that was available to Niagara Mohawk Power Corporation prior to 1982 concerning the potential for cracking in safety-related piping systems at the Nine Mile Point Unit No. 1 nuclear plant.

New York State Public Service Commission (Case 28166) - January 1983 and February 1984
Whether the January 25, 1982, steam generator tube rupture at the Ginna Nuclear Plant was caused by mismanagement.

U.S. Nuclear Regulatory Commission (Case 50-247SP) - May 1983
The economic costs and benefits of the early retirement of the Indian Point nuclear plants.

REPORTS, ARTICLES, AND PRESENTATIONS

Changing Course: A Clean Energy Investment Plan for Dominion Virginia Power. Co-authored with Jeff Loiter and Anna Sommer. August 2013.

Mountain State Maneuver: AEP and FirstEnergy try to stick ratepayers with Risky Coal Plants. September 2013. Co-authored with Cathy Kunkel.

Public Utility Regulation without the Public: The Alabama Public Service Commission and Alabama Power. Co-authored with Anna Sommer. March 2013

A Texas Electric Capacity Market: The Wrong Tool for a Real Problem. Co-authored with Anna Sommer. February 2013.

Dark Days Ahead: Financial Factors Cloud Future Profitability at Dominion's Brayton Point Power Plant. Co-authored with Tom Sanzillo. February 2013.

Report on the Kemper IGCC Project: Cost and Schedule Risks. November 2012.

The Prairie State Coal Plant: the Reality vs. the Promise. August 2012.

The Impact of EPA's Proposed 316(b) Existing Facility Rule on Electric System Reliability, July 2011.

The Economics of Existing Coal-Fired Power Plants, Presentation at EUCI Conference in St. Louis, MO, November 2010.

Presentation to the Indiana Utility Regulatory Commission on the Need for the Proposed Duke Energy Indiana Edwardsport IGCC Project, November 2010.

Reply Comments on Portland General Electric Company's 2009 Integrated Resource Plan, September 2010.

Presentation to the Oregon Public Utility Commission on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on Portland General Electric Company's 2009 Integrated Resource Plan, May 2010.

Comments on the Facility Cost Report for Tenaska's Proposed Taylorville IGCC Plant, April 2010.

Comments on City of Holland Board of Public Work's 2010 Power Supply Plan, April 2010.

Phasing Out Federal Subsidies for Coal, April 2010.

Comments on Draft Portland General Electric Company 2009 Integrated Resource Plan, October 2009.

The Economic Impact of Restricting Mountaintop/Valley Fill Coal Mining in Central Appalachia, August 2009.

Energy Future: A Green Energy Alternative for Michigan, report, July 2009.

Energy Future: A Green Energy Alternative for Michigan, presentation, July 2009.

Preliminary Assessment of East Kentucky Power Cooperative's 2009 Resource Plan, June 2009.

The Financial Risks to Old Dominion Electric Cooperative's Consumer-Members of Building and Operating the Proposed Cypress Creek Power Station, April 2009.

An Assessment of Santee Cooper's 2008 Resource Planning, April 2009.

Nuclear Loan Guarantees: Another Taxpayer Bailout Ahead, Report for the Union of Concerned Scientists, March 2009.

New Hampshire Senate Bill 152: Merrimack Station Scrubber, March 2009.

The Risks of Building and Operating Plant Washington, Presentation to the Sustainable Atlanta Roundtable, December 2008.

The Risks of Building and Operating Plant Washington, Report and Presentation to EMC Board Members, December 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the University of California at Berkeley Energy and Resources Group Colloquium, October 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at Georgia Tech University, October 2008.

Nuclear Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Coal-Fired Power Plant Construction Costs, Synapse Energy Economics, July 2008.

Synapse 2008 CO_2 Price Forecasts, Synapse Energy Economics, July 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation at the NARUC ERE Committee, NARUC Summer Meetings, July 2008.

Are There Nukes In Our Future, Presentation at the NASUCA Summer Meetings, June 2008.

Risky Appropriations: Gambling US Energy Policy on the Global Nuclear Energy Partnership, Report for Friends of the Earth, the Institute for Policy Studies, the Government Accountability Project, and the Southern Alliance for Clean Energy, March 2008.

Don't Get Burned, the Risks of Investing in New Coal-Fired Power Plants, Presentation to the New York Society of Securities Analysts, February 26, 2008.

Don't Get Burned,Report for the Interfaith Center for Corporate Responsibility, February 2008.

The Risks of Participating in the AMPGS Coal Plant, Report for NRDC, February 2008.

Kansas is Not Alone, *the New Climate for Coal*, Presentation to members of the Kansas State Legislature, January 22, 2008.

The Risks of Building New Nuclear Power Plants, Presentation to the Utah State Legislature Public Utilities and Technology Committee, September 19, 2007.

The Risks of Building New Nuclear Power Plants, Presentation to Moody's and Standard & Poor's rating agencies, May 17, 2007.

The Risks of Building New Nuclear Power Plants, U.S. Senate and House of Representative Briefings, April 20, 2007.

Carbon Dioxide Emissions Costs and Electricity Resource Planning, New Mexico Public Regulation Commission, Case 06-00448-UT, March 28, 2007, with Anna Sommer.

The Risks of Building New Nuclear Power Plants, Presentation to the New York Society of Securities Analysts, June 8, 2006.

Conservation and Renewable Energy Should be the Cornerstone for Meeting Future Natural Gas Needs. Presentation to the Global LNG Summit, June 1, 2004. Presentation given by Cliff Chen.

Comments on natural gas utilities' Phase I Proposals for pre-approved full cost recovery of contracts with liquid natural gas (LNG) suppliers and the costs of interconnecting their systems with LNG facilities. Comments in California Public Utilities Commission Rulemaking 04-01-025. March 23, 2004.

The 2003 Blackout: Solutions that Won't Cost a Fortune, The Electricity Journal, November 2003, with David White, Amy Roschelle, Paul Peterson, Bruce Biewald, and William Steinhurst.

The Impact of Converting the Cooling Systems at Indian Point Units 2 and 3 on Electric System Reliability. An Analysis for Riverkeeper, Inc. November 3, 2003.

The Impact of Converting Indian Point Units 2 and 3 to Closed-Cycle Cooling Systems with Cooling Towers on Energy's Likely Future Earnings. An Analysis for Riverkeeper, Inc. November 3, 2003.

Entergy's Lost Revenues during Outages of Indian Point Units 2 and 3 to Convert to Closed-Cycle Cooling Systems. An Analysis for Riverkeeper, Inc. November 3, 2003.

Power Plant Repowering as a Strategy for Reducing Water Consumption at Existing Electric Generating Facilities. A presentation at the May 2003 Symposium on Cooling Water Intake Technologies to Protect Aquatic Organisms. May 6, 2003.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-tiered Holding Companies to Own Electric Generating Plants. A presentation at the 2002 NASUCA Annual Meeting. November 12, 2002.

Determining the Need for Proposed Overhead Transmission Facilities. A Presentation by David Schlissel and Paul Peterson to the Task Force and Working Group for Connecticut Public Act 02-95. October 17, 2002.

Future PG&E Net Revenues From The Sale of Electricity Generated at its Brayton Point Station. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

PG&E's Net Revenues From The Sale of Electricity Generated at its Brayton Point Station During the Years 1999-2002. An Analysis for the Attorney General of the State of Rhode Island. October 2, 2002.

Financial Insecurity: The Increasing Use of Limited Liability Companies and Multi-Tiered Holding Companies to Own Nuclear Power Plants. A Synapse report for the STAR Foundation and Riverkeeper, Inc., by David Schlissel, Paul Peterson, and Bruce Biewald, August 7, 2002.

Comments on EPA's Proposed Clean Water Act Section 316(b) for Cooling Water Intake Structures at Phase II Existing Facilities, on behalf of Riverkeeper, Inc., by David Schlissel and Geoffrey Keith, August 2002.

The Impact of Retiring the Indian Point Nuclear Power Station on Electric System Reliability. A Synapse Report for Riverkeeper, Inc. and Pace Law School Energy Project. May 7, 2002.

Preliminary Assessment of the Need for the Proposed Plumtree-Norwalk 345-kV Transmission Line. A Synapse Report for the Towns of Bethel, Redding, Weston, and Wilton Connecticut. October 15, 2001.

ISO New England's Generating Unit Availability Study: Where's the Beef? A Presentation at the June 29, 2001 Restructuring Roundtable.

Clean Air and Reliable Power: Connecticut Legislative House Bill HB6365 will not Jeopardize Electric System Reliability. A Synapse Report for the Clean Air Task Force. May 2001.

Room to Breathe: Why the Massachusetts Department of Environmental Protection's Proposed Air Regulations are Compatible with Reliability. A Synapse Report for MASSPIRG and the Clean Water Fund. March 2001.

Generator Outage Increases: A Preliminary Analysis of Outage Trends in the New England Electricity Market, a Synapse Report for the Union of Concerned Scientists, January 7, 2001.

Cost, Grid Reliability Concerns on the Rise Amid Restructuring, with Charlie Harak, Boston Business Journal, August 18-24, 2000.

Report on Indian Point 2 Steam Generator Issues, Schlissel Technical Consulting, Inc., March 10, 2000.

Preliminary Expert Report in Case 96-016613, Cities of Wharton, Pasadena, et al v. Houston Lighting & Power Company, October 28, 1999.

Comments of Schlissel Technical Consulting, Inc. on the Nuclear Regulatory Commission's Draft Policy Statement on Electric Industry Economic Deregulation, February 1997.

Report to the Municipal Electric Utility Association of New York State on the Cost of Decommissioning the Fitzpatrick Nuclear Plant, August 1996.

Report to the Staff of the Arizona Corporation Commission on U.S. West Corporation's telephone cable repair and replacement programs, May, 1996.

Nuclear Power in the Competitive Environment, NRRI Quarterly Bulletin, Vol. 16, No. 3, Fall 1995.

Nuclear Power in the Competitive Environment, presentation at the 18th National Conference of Regulatory Attorneys, Scottsdale, Arizona, May 17, 1995.

The Potential Safety Consequences of Steam Generator Tube Cracking at the Byron and Braidwood Nuclear Stations, a report for the Environmental Law and Policy Center of the Midwest, 1995.

Report to the Public Policy Group Concerning Future Trojan Nuclear Plant Operating Performance and Costs, July 15, 1992.

Report to the New York State Consumer Protection Board on the Costs of the 1991 Refueling Outage of Indian Point 2, December 1991.

Preliminary Report on Excess Capacity Issues to the Public Utility Regulation Board of the City of El Paso, Texas, April 1991.

Nuclear Power Plant Construction Costs, presentation at the November, 1987, Conference of the National Association of State Utility Consumer Advocates.

Comments on the Final Report of the National Electric Reliability Study, a report for the New York State Consumer Protection Board, February 27, 1981.

OTHER SIGNIFICANT INVESTIGATIONS AND LITIGATION SUPPORT WORK

Reviewed the salt deposition mitigation strategy proposed for Reliant Energy's repowering of its Astoria Generating Station. October 2002 through February 2003.

Assisted the Connecticut Office of Consumer Counsel in reviewing the auction of Connecticut Light & Power Company's power purchase agreements. August and September, 2000.

Assisted the New Jersey Division of the Ratepayer Advocate in evaluating the reasonableness of Atlantic City Electric Company's proposed sale of its fossil generating facilities. June and July, 2000.

Investigated whether the 1996-1998 outages of the three Millstone Nuclear Units were caused or extended by mismanagement. 1997 and 1998. Clients were the Connecticut Office of Consumer Counsel and the Office of the Attorney General of the Commonwealth of Massachusetts.

Investigated whether the 1995-1997 outages of the two units at the Salem Nuclear Station were caused or extended by mismanagement. 1996-1997. Client was the New Jersey Division of the Ratepayer Advocate.

Assisted the Associated Industries of Massachusetts in quantifying the stranded costs associated with utility generating plants in the New England states. May through July, 1996

Investigated whether the December 25, 1993, turbine generator failure and fire at the Fermi 2 generating plant was caused by Detroit Edison Company's mismanagement of fabrication, operation or maintenance. 1995. Client was the Attorney General of the State of Michigan.

Investigated whether the outages of the two units at the South Texas Nuclear Generating Station during the years 1990 through 1994 were caused or extended by mismanagement. Client was the Texas Office of Public Utility Counsel.

Assisted the City Public Service Board of San Antonio, Texas in litigation over Houston Lighting & Power Company's management of operations of the South Texas Nuclear Generating Station.

Investigated whether outages of the Millstone nuclear units during the years 1991 through 1994 were caused or extended by mismanagement. Client was the Office of the Attorney General of the Commonwealth of Massachusetts.

Evaluated the 1994 Decommissioning Cost Estimate for the Maine Yankee Nuclear Plant. Client was the Public Advocate of the State of Maine.

Evaluated the 1994 Decommissioning Cost Estimate for the Seabrook Nuclear Plant. Clients were investment firms that were evaluating whether to purchase the Great Bay Power Company, one of Seabrook's minority owners.

Investigated whether a proposed natural-gas fired generating facility was need to ensure adequate levels of system reliability. Examined the potential impacts of environmental regulations on the unit's expected construction cost and schedule. 1992. Client was the New Jersey Rate Counsel.

Investigated whether Public Service Company of New Mexico management had adequately disclosed to potential investors the risk that it would be unable to market its excess generating capacity. Clients were individual shareholders of Public Service Company of New Mexico.

Investigated whether the Seabrook Nuclear Plant was prudently designed and constructed. 1989. Clients were the Connecticut Office of Consumer Counsel and the Attorney General of the State of Connecticut.

Investigated whether Carolina Power & Light Company had prudently managed the design and construction of the Harris nuclear plant. 1988-1989. Clients were the North Carolina Electric Municipal Power Agency and the City of Fayetteville, North Carolina.

Investigated whether the Grand Gulf nuclear plant had been prudently designed and constructed. 1988. Client was the Arkansas Public Service Commission.

Reviewed the financial incentive program proposed by the New York State Public Service Commission to improve nuclear power plant safety. 1987. Client was the New York State Consumer Protection Board.

Reviewed the construction cost and schedule of the Hope Creek Nuclear Generating Station. 1986-1987. Client was the New Jersey Rate Counsel.

Reviewed the operating performance of the Fort St. Vrain Nuclear Plant. 1985. Client was the Colorado Office of Consumer Counsel.

WORK HISTORY

2010 - President, Schlissel Technical Consulting, Inc.

2000 - 2009: Senior Consultant, Synapse Energy Economics, Inc.

1994 - 2000: President, Schlissel Technical Consulting, Inc.

1983 - 1994: Director, Schlissel Engineering Associates

1979 - 1983: Private Legal and Consulting Practice

1975 - 1979: Attorney, New York State Consumer Protection Board

1973 - 1975: Staff Attorney, Georgia Power Project

EDUCATION

1983-1985: Massachusetts Institute of Technology
Special Graduate Student in Nuclear Engineering and Project Management,

1973: Stanford Law School,
Juris Doctor

1969: Stanford University
Master of Science in Astronautical Engineering,

1968: Massachusetts Institute of Technology
Bachelor of Science in Astronautical Engineering,

PROFESSIONAL MEMBERSHIPS

- New York State Bar since 1981
- American Nuclear Society

EXHIBIT DAS-2

Livezey, Amy E

From:	Jamil, Dhiaa M
Sent:	Saturday, October 11, 2014 7:27 PM
To:	Good, Lynn J
Subject:	Re: Eport
Follow Up Flag:	Follow up
Flag Status:	Completed
Categories:	Edwardsport

I'll get you exact numbers next week.

----- Original Message -----
From: Good, Lynn J
Sent: Saturday, October 11, 2014 07:26 PM Eastern Standard Time
To: Jamil, Dhiaa M
Subject: Re: Eport

Thanks

Sent from my iPad

> On Oct 11, 2014, at 7:25 PM, Jamil, Dhiaa M <Dhiaa.Jamil@duke-energy.com> wrote:
>
> August was good (just a little less than July). September was an outage month so metrics will be very low. The outage was planned.
>
> ----- Original Message -----
> From: Good, Lynn J
> Sent: Saturday, October 11, 2014 07:22 PM Eastern Standard Time
> To: Jamil, Dhiaa M
> Subject: Eport
>
> Do you have an update on operating results for August and September?
>
> Sent from my iPad

Livezey, Amy E

From: Jamil, Dhiaa M
Sent: Tuesday, October 14, 2014 1:12 PM
To: Good, Lynn J
Subject: Edwardsport data

Follow Up Flag: Follow up
Flag Status: Completed

Categories: Edwardsport

Lynn,
See below the performance data for Edwardsport.
August was another strong month (75% commercial availability and 90% gasification availability).
September had a scheduled outage. The numbers reflect that. October will also be a low numbers month as we are now coming out of the outage.
Let me know if you have questions.
Dhiaa.

	Site Capacity Factor (Natural Gas & Syngas)	Capacity Factor (Syngas Only)	Equivalent Availability Factor (NG&SG)	Gasification Availability Factor
Sep-14	14.93	13.34	27.13	26.57%
2014 YTD	40.75	35.96	65.96	55.35%
Q3, 2014	48.45	45.76	60.88	69.66%
Jun-13	12.38	9.92	82.37	21.53
Jul-13	26.19	7.96	68.97	14.45
Aug-13	60.39	50.56	80.83	76.01
Sep-13	31.66	24.83	63.36	47.96
Oct-13	43.31	40.84	61.32	58.60
Nov-13	28.28	22.77	65.87	32.19
Dec-13	32.39	19.50	61.46	41.69
Jan-14	17.54	2.30	60.78	4.84
Feb-14	5.21	0.12	41.72	0.61
Mar-14	32.77	26.92	77.25	50.93
Apr-14	37.99	33.89	68.26	61.56
May-14	66.80	65.68	87.77	82.79
Jun-14	58.39	54.86	73.02	84.74
Jul-14	67.63	63.47	79.27	90.99
Aug-14	61.70	59.42	75.15	90.02
Sep-14	14.93	13.34	27.13	26.57
Cml thru Sep-14	37.63	31.27	67.36	49.78

From: Byrer, Doug
Sent: Tuesday, October 14, 2014 7:59 AM
To: Stultz, Jack L
Cc: Marchino, Craig P
Subject: RE: Tables

Please see the revised table for September, including Q3 data where applicable, below:

090015313-0024181

EXHIBIT DAS-3

OUCC
IURC Cause No. 43114 IGCC-12 and IGCC-13
Data Request Set No. 15
Received: August 27, 2014

OUCC 15.16

Request:

Did the IGCC plant operate at 100% capacity during any of the following times? If the answer is yes, please provide all documentation showing the date and period of time over which the plant operated at 100% of capacity.

a. June 7 – 30, 2013;
b. The month of July 2013;
c. The month of August 2013;
d. The month of September 2013;
e. The month of October 2013;
f. The month of November 2013;
g. The month of December 2013;
h. The month of January 2014;
i. The month of February 2014; and
j. The month of March 2014;

Objection:

Duke Energy Indiana objects to this request as vague and ambiguous, particularly its reference to "100% capacity."

Response:

Subject to and without waiving or limiting its objections and responding as to periods of time when Edwardsport was at 100% of its seasonal capacity, Duke Energy Indiana responds as follows:

a. No.
b. No.
c. Yes. Please see Confidential Attachment OUCC 15.16-A, which provides data showing that Edwardsport operated at its seasonal net dependable capacity on August 9, 2013.
d. No.
e. No.
f. No.
g. No.

h. No.
i. No.
j. No.

EXHIBIT DAS-4-CONFIDENTIAL

EXHIBIT DAS-5-CONFIDENTIAL

EXHIBIT DAS-6

SDI
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 1
Received: June 16, 2014

DECLASSIFICATION OF CONFIDENTIAL RESPONSE 9-10-14
SDI 1.3

Request:

Provide monthly actual heat rates for coal consumption for the Edwardsport IGCC plant for 2013 and 2014 to date.

Objection:

Duke Energy Indiana objects to this request to the extent that it requests information outside of the relevant time period of this proceeding as not reasonably calculated to lead to admissible evidence. Duke Energy Indiana also objects to this request as vague and ambiguous, particularly the phrase "monthly actual heat rates for coal consumption."

Response:

Subject to and without waiving or limiting its objections, the monthly station net heat rate for the period June 2013 through March 2014, as calculated by the GADS system, is as follows:

DATE	Net Heat Rate (Btu/kWhr)
June 2013	16,791
July 2013	14,777
August 2013	12,402
September 2013	14,770
October 2013	12,717
November 2013	12,551
December 2013	16,452
January 2014	17,559
February 2014	20,981
March 2014	14,056

Note that this net heat rate calculation includes all fuel burned and generation produced from the facility post-in-service and is not specific to only coal consumption. Additionally, the June 2013 figure is not completely accurate because the pre-commercial generation was not included in the calculation.

EXHIBIT DAS-7

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 16
Received: October 6, 2014

CAC 16.1

Request:

For the 2014-2015 MISO Planning Year please provide the following data used by MISO for its Loss of Load Expectation study:

a. Edwardsport's unforced capacity (UCAP) value
b. Edwardsport's Equivalent Forced Outage Rate demand (EFORd)

Objection:

Duke Energy Indiana objects to this Request on the grounds that Duke Energy Indiana doesn't know what "data [was] used by MISO for its Loss of Load Expectation study."

Response:

Subject to and without waiving or limiting its objections and in the spirit of cooperation,

a. To Duke Energy Indiana's knowledge, MISO does not use UCAP values in its LOLE analysis. Instead, according to the 2014 LOLE Study Report, MISO uses Generator Verification Test Capacities (GVTC) and Monthly Net Dependable Capacities (NDC). The GVTC values that Duke Energy Indiana had provided MISO that coincided with the general timeframe during which the 2014 LOLE Study was performed were as follows:
    - 466.2 MW provided prior to the 3/1/13 deadline for the PY 2013/14 Planning Resource Auction
    - 491.3 MW provided prior to the 7/31/13 deadline for the Transitional Auction

   Duke Energy Indiana does not know what MISO used in its study for the GVTC nor for the monthly NDCs.
b. According to the 2014 LOLE Study Report, MISO used EFORd values over the 5-year period January 2008 to December 2012 in its PY 2014/15 Study. However, for units with less than 12 months of unit-specific EFORd data at the time the 2014 LOLE Study was performed, according to the 2014 LOLE Study Report, MISO used the corresponding MISO class average forced outage rate data. If a particular MISO class had less than 30 units, then MISO used NERC class average forced outage rate data. Duke Energy Indiana does not know what was used specifically for Edwardsport.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 16
Received: October 6, 2014

CAC 16.2

Request:

For the 2015-2016 MISO Planning Year please provide the following data used by MISO for its Loss of Load Expectation study:

a. Edwardsport's unforced capacity (UCAP) value
b. Edwardsport's Equivalent Forced Outage Rate demand (EFORd)

If DEI does not currently possess this information, please provide it when DEI does.

Objection:

Duke Energy Indiana objects to this Request on the grounds that Duke Energy Indiana doesn't know what "data [was] used by MISO for its Loss of Load Expectation study."

Response:

Subject to and without waiving or limiting its objections, and in the spirit of cooperation,

a. To Duke Energy Indiana's knowledge, MISO does not use UCAP values in its LOLE analysis. According to the draft 2015 LOLE Study Report, the 2015-2016 planning year LOLE study utilized the 2014 Planning Resource Auction converted capacity as a starting point for which resources to include in the study. It is unclear to Duke Energy Indiana what this means with regard to what MISO used for Edwardsport in its study. The GVTC value that Duke Energy Indiana had provided MISO that was used for the PY 2014/15 Auction was 570.0 MW.
b. According to the draft 2015 LOLE Study Report, MISO used EFORd values over the 5-year period January 2009 to December 2013 in its study. However, for units with less than 12 months of unit-specific EFORd data at the time the 2015 LOLE Study was performed, according to the draft 2015 LOLE Study Report, MISO MISO used the corresponding MISO class average forced outage rate data. If a particular MISO class had less than 30 units, MISO used the overall MISO weighted class average forced outage rate of 7.67%. Duke Energy Indiana does not know what was used specifically for Edwardsport.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 16
Received: October 6, 2014

CAC 16.3

Request:

Please provide Edwardsport's Forced Outage Rate (FOR), Equivalent Forced Outage Rate (EFOR) and forced outage hours for each month of the period June 2013 through August 2014.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is not reasonably calculated to lead to admissible evidence in this proceeding to the extent it seeks information outside of the April 2013 through March 2014 reporting period.

Response:

Subject to and without waiving or limiting its objections, see Confidential Attachment CAC 16.3-A for the requested Forced Outage Rate and Equivalent Forced Outage Rate data for June 2013 through April 2014.

EXHIBIT DAS-8-CONFIDENTIAL

EXHIBIT DAS-9-CONFIDENTIAL

EXHIBIT DAS-10

IURC Cause No. 43114 IGCC-8
Data Request Set No. 4
Received: March 13, 2012
CAC 4.4

Request:

Please explain in detail the operational relationship, if any, between the "initial start-up and generation of test power for sale" from CTG-1 and CTG-2 referenced in the subject Notification in Joint Intervenors Data Request 4.3 and the classification or declaration by the Company of all or part of the Edwardsport plant as "in service" for accounting and ratemaking purposes.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is irrelevant and not calculated to lead to the discovery of relevant or admissible information in this proceeding. The IGCC-8 proceeding provides a progress report for ongoing review of construction of the Edwardsport Project as it proceeds and seeks cost recovery for the April – September 2011 time frame. Any request for information outside of that six month period is both irrelevant and outside the scope of this proceeding.

Response:

Subject to and without waiving the foregoing general and specific objections, Duke Energy Indiana states as follows: The "initial start-up and generation of test power for sale" occurs while the plant is still in test phase, which is earlier than when the plant will be declared as in-service for accounting and ratemaking purposes. The plant will be declared in-service for accounting and rate-making purposes when testing is complete and the plant is ready for its intended use as an integrated gasification combined cycle generating facility.

Witness: Diana L. Douglas

EXHIBIT DAS-11

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 8
Received: October 3, 2014

DEI-IG 8.2

Request:

How did the Company come to the determination that NPI testing has been completed with NPI Phase 6 and 8 tests yet to be completed?

Response:

Duke Energy Indiana reasonably believed that GE's NPI testing program was completed in September 2013 after receiving the notification from GE that it did not require additional tests under its NPI testing program. Even with this notification that NPI was completed, the Company was aware that there remained additional tests required under Exhibit T of the Duke/GE contract (which were previously included under the NPI testing list for reporting purposes, but were not originally contemplated as such under Exhibit X of the Duke/GE contract).

EXHIBIT DAS-12

DEI-IG
IURC Cause No. 43114 IGCC-12
Data Request Set No. 1
Received: May 12, 2014

SUPPLEMENTAL RESPONSE 12-5-14
SUPPLEMENTAL INFORMATION IN BOLD

DEI-IG 1.8

Request:

Referring to the Settlement Agreement, paragraph 2E and the definition of Construction Costs:

a. Does Duke believe the date of final completion has been achieved?

b. If the answer to the prior question is no, when does Duke believe final completion will be achieved?

c. Please provide the date each of the conditions to substantial completion occurred, items (a) through (f), as reflected on Attachment A to the Settlement Agreement.

d. If any of the conditions to substantial completion have not occurred, items (a) through (f), as reflected on Attachment A to the Settlement Agreement, please provide an explanation of the reasons and the expected date each condition will occur.

e. Please provide the date each of the conditions to final completion occurred, items (a) through (e), as reflected on Attachment A to the Settlement Agreement.

f. If any of the conditions to final completion have not occurred, items (a) through (e), as reflected on Attachment A to the Settlement Agreement, please provide an explanation of the reasons and the expected date each condition will occur.

Response:

a. No.

b. Given that Substantial Completion (as defined by the Duke/GE contract) has not yet occurred, it is difficult to estimate when Final Completion will occur. A more accurate estimate can be provided once the performance testing required for Substantial Completion has occurred. The thermal performance testing is currently scheduled for sometime in the next few weeks. **The performance test and ramping demonstrations are complete with Duke Energy Indiana taking exception to certain adjustments made by GE to the heat rate calculation from the performance test. Duke Energy has reserved its rights and remedies under the Duke Energy/GE Contract, but accepts the performance test as complete because if GE is correct in its adjustments, the heat rate guarantee has been met. There is no dispute about the MW guarantee having been met. The ramp demonstration has been successfully completed. GE and Duke Energy have discussed and agreed upon a Punch List, subject to contractual remedies for any remaining items in dispute. The parties are currently discussing Documentation and a certificate of substantial completion, and anticipate that Substantial Completion will be achieved before the end of 2014. Thereafter, upon completion of the Punch List and further certification, Final Completion will have been achieved. The parties currently anticipate that this will occur in the spring of 2015 as certain Punch List items require a full station outage to be completed.**

c. Of the following:

(a) Delivery of all GEP Equipment shall have occurred;

(b) the performance of the Work shall be complete (other than Work that by its nature cannot be completed until after Substantial Completion (e.g., warranty Work)), with the exception of the Punch List;

(c) the Facility shall have satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees;

(d) the Seller shall have delivered to the Buyer all Documentation that the Seller is required to deliver to the Buyer pursuant to this Contract, with the exception of the Punch List;

(e) the Seller shall have provided all training required by Exhibit S, with the exception of the Punch List; and

(f) the Seller shall have delivered to the Buyer a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied.

Only (a) and (e) have occurred. The delivery of major GEP Equipment was completed September 29, 2011 and the training required by Exhibit S was also completed. According to documentation provided by GE, it appears that the final required training was completed by GE on September 26, 2013. Duke and GE continue to work on completion of the additional components of Substantial Completion. **(b) occurred November 12, 2014, upon completion of the ramping demonstration and (c) occurred May 16, 2014.**

d. Please see the response to subpart (b) above. Duke Energy Indiana continues to review the data from the May 2014 performance test and cannot yet state whether the

Facility has satisfied the Minimum Performance Guarantees and the Make-Right Performance Guarantees. Additionally, until the contractually-required demonstrations have occurred, Duke Energy Indiana and GE could not agree that the "performance of the Work shall be complete" nor could "a certificate signed by the Seller certifying that all of the preceding conditions in this Section have been satisfied" be delivered by GE to Duke Energy Indiana. GE is working on compiling the voluminous Documentation required to be delivered to Duke under the contract, but is not yet finished. **Regarding item (d), certain Documentation still remains outstanding. On November 20, 2014, GE delivered a draft certificate of substantial completion to Duke Energy for its review. Duke Energy has not yet completed its review and has not yet signed accepting the certificate. As such, subpart (f) is not complete, but is anticipated to be completed by the end of 2014.**

e. Please see the response to subpart (a) above.

f. Please see the response to subpart (d) above.

EXHIBIT DAS-13

OUCC
IURC Cause No. 43114 IGCC-12 and IGCC-13
Data Request Set No. 15
Received: August 27, 2014

OUCC 15.18

Request:

After Duke declared the IGCC plant "in-service" on June 7, 2013, did the IGCC plant achieve the Contractual Performance Guarantee of 632,000 kW in the year 2013? If the answer is yes, please provide all documentation showing that the IGCC plant achieved the Contractual Performance Guarantee of 632,000 kW in 2013.

Objection:

Duke Energy Indiana objects to this Request as vague, ambiguous and potentially mischaracterizing the 2007 Duke Energy/GE Contract.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows: The 2007 Duke Energy/GE Contract provides that "The Seller guarantees that during the Performance Test, the Facility will produce a base load Net Facility Electrical Output (Guaranteed) of no less than 632,000 kW when corrected to the guarantee conditions contained in Section T3." Because the Performance Test was not performed until May 15-16, 2014, no.

EXHIBIT DAS-14

DEI-IG
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 8
Received: October 3, 2014

SUPPLEMENTAL RESPONSE 12-5-14
SUPPLEMENTAL INFORMATION IN BOLD
DEI-IG 8.3

Request:

Have the NPI Phase 6 and 8 tests been completed yet? If so, when?

Response:

Please see the Company's prior responses to DEI-IG 8.1 and 8.2.

Supplemental Response:

Upon request by Counsel for DEI-IG, Duke Energy Indiana is providing the following supplemental information: It is Duke Energy Indiana's understanding that GE completed its NPI testing program in September 2013. The remaining tests listed under NPI Phases 6-8 in the table referred to in DEI-IG 8.1 (not marked as either completed or deleted) are duplicates of the tests required by the Duke/GE Contract in Exhibit T and cover system operability demonstrations and the thermal performance test. The system operability demonstrations were completed November 12, 2014 and the thermal performance test on May 15 and 16, 2014.

EXHIBIT DAS-15-CONFIDENTIAL

EXHIBIT DAS-16

CAC
IURC Cause No. 43114 IGCC 11
Data Request Set No. 2
Received: July 5, 2013

SUPPLEMENTAL RESPONSE 7-29-13
SUPPLEMENTAL RESPONSE IS IN BOLD

CAC 2.1

Request:

Reference Mr. Stultz's Prefiled Testimony of July 3, 2013, p. 5, lines 1-6, regarding the Company's declaration of Edwardsport in service and the related operation of the gasifiers.

a. State with specificity the date and time at which the Train 1 Gasifier was "lit off."

b. State with specificity the dates and times during which the Train 1 and Train 2 Gasifiers were "run together."

c. Please state the reason(s) that the length of time for running both gasifiers together provided in the response to 2.1(b) was determined by the Company to be sufficient for an in service declaration.

Response:

a. Please see response to subpart (b) below.

b. The times listed below represent gasifier start times. The total time both gasifiers were in service together totaled 119 hours. **The end date and time are 6/10/2013 at 14:34.**

Gasifier 1	6/5/2013 15:33
Gasifier 2	5/31/2013 14:04

c. The Company declared the Edwardsport IGCC Plant in service in accordance with FERC accounting guidelines.

Witness: Jack L. Stultz for a.b. and Diana Douglas for c.

EXHIBIT DAS-17

OUCC
IURC Cause No. 43114 IGCC-12 and IGCC-13
Data Request Set No. 15
Received: August 27, 2014

OUCC 15.2

Request:

Was Duke the sole entity that decided to declare the IGCC plant "in service" on June 7, 2013? If the answer is no, please identify all other entities that were part of the decision to declare the IGCC plant "in service" on June 7, 2013.

Response:

Yes.

EXHIBIT DAS-18-CONFIDENTIAL

EXHIBIT DAS-19

CAC
IURC Cause No. 43114 IGCC-12
Data Request Set No. 2
Received: March 20, 2014

CAC 2.1

Request:

In his prefiled testimony in Cause No. 38707-FAC-99, DEI witness Swez states, in pertinent part:

> On June 7, 2013, the Edwardsport IGCC generating station began commercial operation and has since performed as expected. For example, on August 9, Edwardsport IGCC reached approximately 586 net MW output under syngas production. Since commercial operation, the station has produced electricity using both syngas and natural gas, with the majority of production from syngas.
> . . .
>
> During times when Edwardsport IGCC is performing testing, tuning, and optimization, the station is offered [to MISO] with a commitment status of must-run
> with the minimum and maximum output dictated by the specific schedule and unit availability. During these situations, the output of the station is coded as testing. The Company's offer to MISO essentially results with the MISO dispatch following the output of the units during this time rather than MISO determining the level of output the unit. However, during situations when syngas is not available,
> testing, tuning, and optimization is not required with natural gas operation, and the
> station is available on natural gas operation, the unit is offered to MISO as an economic resource and can be committed and dispatched at MISO's discretion. During these situations, the output of the station is not coded as testing.

With respect to the time period of June 7, 2013 through February 28, 2014, please provide the following information relative to the operation of the Edwardsport IGCC generating station:

> a. By individual calendar date, the number of hours during which the output of the station has been coded as testing and the amounts of generation and resulting revenues during those hours;
>
> b. By individual calendar date, the number hours during which the output of the stations has NOT been coded as testing but instead offered to MISO as an

economic resource and the amount of generation and resulting revenues during those hours;

c. By individual calendar month, the number of hours during which the output of the station has been coded as testing and the amounts of generation and resulting revenues during those hours;

d. By individual calendar month, the number of hours during which the output of the station has NOT been coded as testing but instead offered to MISO as an economic resource and the amounts of generation and resulting revenues during those hours;

e. By individual calendar date, the minimum and maximum output during the period the station was classified as testing;

f. By individual calendar date, the minimum and maximum output during the period the station was NOT classified as testing but instead offered to MISO as an economic resource;

g. By individual calendar date, the amounts of generation produced from syngas and natural gas, respectively; and

h. By individual calendar month, the amounts of generation produced from syngas and natural gas, respectively.

Objection:

Duke Energy Indiana objects to this Request on the grounds that it is not reasonably calculated to lead to admissible evidence in this proceeding. The relevant time period for this proceeding is April 1, 2013 through September 30, 2013. Duke Energy Indiana objects to producing information from outside of the relevant time period. Duke Energy Indiana also objects to this Request to the extent it has a different definition of the term "testing" than Mr. Swez used in his FAC testimony. Duke Energy Indiana's response to this Request is per Mr. Swez's understanding and use of the term "testing." Duke Energy Indiana further objects to subparts (g) and (h) of this Request on the grounds that the Plant's metering does not differentiate between electrical energy produced by gasified coal or natural gas.

Response:

Subject to and without waiving or limiting its objections, Duke Energy Indiana responds as follows:

a. All hours Edwardsport ran during the time period in question have been categorized as "testing," with assignment to native load, for purposes of stacking generation in the Company's PACE model. This is consistent with the Company's categorization of generation during testing periods at other generating units. Note that during the time period in question, Edwardsport was not cleared by MISO while being offered with a commitment status of "Economic" in any hour and thus, all generation was the result of a "Must Run" commitment status. In addition, see Attachment CAC 2.1 A, which represents the real-time generation, as well as the day-ahead asset energy, real-time non-excessive, and real-time excessive energy amounts from Edwardsport. Note that this represents only the revenues as a result of the units' participation in only the MISO energy markets. To calculate all "resulting revenues," additional credits and adjustments from ARRs/FTRs, capacity, ancillary services, distribution of losses, make whole payments, etc. would need to be included.

b. Please see the Company's response to subpart (a) above.
c. Please see the Company's response to subpart (a) above.
d. Please see the Company's response to subpart (a) above.
e. Please see the Company's response to subpart (a) above.
f. N/A
g. See above objection.
h. See above objection. Answering further, please see Confidential Attachment OUCC 3.2-A, as previously produced in this proceeding.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: June 27, 2014

SUPPLEMENTAL RESPONSE 10-3-14
SUPPLEMENTAL INFORMATION IS IN BOLD
CAC 6.8

Request:

Identify all hours during the IGCC-12 and 13 periods when the Edwardsport IGCC was on "must run/testing" status for MISO dispatch.

a) For each hour so identified, what was the fuel being used for the Edwardsport IGCC?

Objection:

Duke Energy Indiana further objects to this Request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence in this proceeding. Duke Energy Indiana also objects to this request as overbroad and unduly burdensome.

Supplemental Response (10-3-14):

In light of the Commission's ruling on the Motion to Compel, Duke Energy Indiana is providing the following supplemental information:

Assuming the reference to "testing status" is intended to refer to Mr. Swez's FAC testimony discussing Duke Energy Indiana's internal coding of Edwardsport output as testing, Duke Energy Indiana responds as follows:

From April 2013 through March 2014, all energy generated by Edwardsport was offered to MISO with a commit status of Must Run. As stated in Mr. Swez's testimony, the output of the plant was coded as testing for internal purposes.

CAC
IURC Cause Nos. 43114 IGCC-12 and IGCC-13
Data Request Set No. 6
Received: June 27, 2014

SUPPLEMENTAL RESPONSE 10-3-14
SUPPLEMENTAL INFORMATION IS IN BOLD
CAC 6.10

Request:

Through March 31, 2014, was all generation from the Edwardsport IGCC on "must run/testing" status for MISO dispatch?

a) If not, explain fully.

Objection:

Duke Energy Indiana objects to this request on the grounds that it is not reasonably calculated to lead to the discovery of admissible evidence in this proceeding.

Supplemental Response (10-3-14):

In light of the Commission's ruling on the Motion to Compel, Duke Energy Indiana is providing the following supplemental information:

Subject to and without waiving or limiting its objections and assuming the reference to "testing status" is intended to refer to Mr. Swez's FAC testimony discussing Duke Energy Indiana's internal coding of Edwardsport output as testing, Duke Energy Indiana responds as follows: From April 2013 through March 31, 2014, yes.