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PUBLIC SERVICE
COMMISSION

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Mr. Jeff Derouen
Executive Director
Kentucky Public Service Commission
211 Sower Boulevard
Frankfort, KY 40602

April 28, 2011

RE: ***VERIFIED APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG-TERM PURCHASE CONTRACT***
CASE NO. *2011-00099*

Dear Mr. Derouen:

Please find enclosed and accept for filing the original and ten (10) copies of the response of Louisville Gas and Electric Company to the Initial Information Request of Commission Staff dated April 15, 2011, in the above-referenced matter.

Also enclosed are an original and ten (10) copies of a Petition for Confidential Protection regarding information provided in response to Question Nos. 2, 4, 5, 9, and 10.

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

Sincerely,

Robert M. Conroy

Enclosures

cc: Parties of Record

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

VERIFIED APPLICATION OF LOUISVILLE GAS AND	)
ELECTRIC COMPANY FOR AN ORDER PURSUANT	) CASE NO.
TO KRS 278.300 AND FOR APPROVAL OF LONG	) 2011-00099
TERM PURCHASE CONTRACT	)

RESPONSE OF
LOUISVILLE GAS AND ELECTRIC COMPANY
TO THE INITIAL INFORMATION REQUEST OF COMMISSION STAFF
DATED APRIL 15, 2011

FILED: April 28, 2011

VERIFICATION

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

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

Lonnie E. Bellar

Lonnie E. Bellar

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of April 2011.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 22, 2014

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Charles R. Schram**, being duly sworn, deposes and says that he is Director – Energy Planning, Analysis and Forecasting for LG&E and KU Services Company, and that he has personal knowledge of the matters set forth in the responses for which he is identified as the witness, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Charles R Schram

Charles R. Schram

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 28th day of April 2011.

Victoria B. Harper (SEAL)
Notary Public

My Commission Expires:

Sept 22, 2014

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 1

Witness: Lonnie E. Bellar

Q-1. Refer to page 5 of the March 16, 2011 applications filed by LG&E and KU.

a. Identify and describe all the liabilities of LG&E/KU that result from participation in the Inter-Company Power Agreement ("ICPA') under which energy and capacity is obtained from the Ohio Valley Electric Corporation ("OVEC"). Such liabilities include, but are not limited to "Take or Pay" arrangements, maintenance responsibilities, decommissioning costs, catastrophic failures, post-retirement benefits, new facilities, etc. Include a narrative discussion of the potential financial ramifications that could arise from these liabilities.

b. Explain whether any liabilities would be eliminated and which would remain if LG&E/KU did not participate in the Amended and Restated Power Agreement.

c. Explain whether the participating companies in the ICPA have input to decisions regarding escalations of cost responsibilities for which the companies may have to contribute. If yes, describe the manner in which the participation takes place.

A-1. a. Please note that the Amended and Restated ICPA for which the Companies are seeking approval in this proceeding does not change in any way the kinds or categories of liabilities the Companies currently have under the Commission-approved ICPA that extends through 2026. Nor does the Amended and Restated ICPA change the Companies' proportional responsibilities for OVEC costs; rather, the new agreement extends the Companies' ability to receive what is anticipated to be relatively low-cost power from OVEC over a longer term (through 2040).

There are three billing components associated with the capacity and energy that LG&E/KU receive from their participation in the ICPA. These components are the Demand, Energy, and Transmission Charges, which are set out in Article 5 of the ICPA.

- **Demand Charges** consist of Capital Improvement Costs, Debt Expenses, Operation and Maintenance Costs, Administrative and General Costs, Transmission and Dispatch Costs, Taxes, ROE Costs, Postretirement Benefit Obligation Costs, and Decommissioning and Demolition Obligation Costs.

- **Energy Charges** consist of Coal Costs, Allowance Costs, and other fuel related costs (reagents, fuel oil, and coal handling less byproduct sales revenue).
- **Transmission Charges** consist of Transmission related costs less any transmission charges credited to Demand Charge.

The Sponsors (including the Companies) are obligated to pay the Demand Charges, regardless of whether they elect to receive energy from the OVEC assets. Sponsors may be liable for minimum generation charges and dispatch costs should they not take their minimum energy related to their ownership share. LG&E/KU typically receive their full allotment, in accordance with their ownership share, and, accordingly typically do not pay minimum generation charges and/or associated dispatch costs.

Article 7 of the ICPA further provides that the Sponsors shall be responsible for paying the costs of replacement facilities, additional facilities (including those needed for environmental compliance), and post-retirement benefit obligations.

The potential financial ramifications of these responsibilities are essentially no different than those associated with coal-fired generating units the Companies own. Just as with the Companies' units, the OVEC units must be (and are being) properly maintained, environmentally compliant, and run competently and efficiently. Just as with the Companies' units, accidents can happen and unforeseen events can occur. The difference with the OVEC arrangement is that the Companies share those costs and risks with the other Sponsors. Again, the Companies are already obligated to share those costs and risks—and the Companies' customers already benefit from attractively priced OVEC energy—under the current ICPA.[1]

b. As described above, the Companies have all the same kinds and categories of liabilities through 2026 under the current ICPA as they would have under the Amended and Restated ICPA. Therefore, no liabilities would be eliminated and all existing liabilities would remain if the Companies did not participate in the Amended and Restated ICPA.

c. The participating companies have input in the decisions made by OVEC through the OVEC board of directors. Each participating company has a representative on the board to govern the business of OVEC. Annually, and sometimes more often if needed, OVEC presents a projection of costs on the ICPA Billable Cost Summary, which is reviewed and approved by the board.

[1] The Commission approved the current ICPA in Case No. 2004-00395.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 2

Witness: Lonnie E. Bellar

Q-2. Explain whether the participating companies in the ICPA conduct plant inspections to assess the condition of the generating units and associated facilities.

a. If yes, describe the extent and frequency of the inspections. Include the results of the most recent inspection.

b. If no, explain why, with the vested interest of the companies in the facilities, an inspection would not be appropriate.

A-2. The OVEC Sponsors (including the Companies) can conduct plant inspections to assess the condition of the generating units and associated facilities at any time, and the Sponsors collectively review the status of the OVEC units and operations through their participation on OVEC's board of directors.

In July 2004, the URS Corporation ("URS") was commissioned to perform an independent Engineering Assessment for the Remaining Life and Production Capabilities, Environmental Remediation/ Restoration, and Demolition/Decommissioning of the OVEC Assets. This study was updated in September 2005 and is attached hereto. OVEC is currently in the process of updating that report with URS. URS will be visiting the plants again in May, and OVEC anticipates receiving a draft report by June 2011.

Additionally, OVEC uses AEP Engineering Services on a continuing basis. In addition to consulting with their subject matter experts on unit outages, problems, and issues at the plants throughout the year, OVEC meets with their Engineering Staff in Columbus on an annual basis to review plant maintenance plans for future years.

In July 2010, the Companies performed their own investigation of a corrosion fatigue outage related to tube failures at OVEC's Clifty Creek Generating Station. A copy of the Companies' internal report concerning the outage and lessons learned from it is attached hereto and is being provided under a petition for confidential protection.

INDEPENDENT TECHNICAL REVIEW
KYGER CREEK
& CLIFTY CREEK PLANTS
OHIO VALLEY ELECTRIC CORPORATION

By
URS Corporation

Rev. 1
September 15, 2005

URS

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EXECUTIVE SUMMARY

Ohio Valley Electric Corporation / Indiana-Kentucky Electric Corporation (OVEC) contracted URS Corporation (URS) to provide an independent technical review of the current condition and the operational and maintenance plans of their Kyger Creek (Kyger) and Clifty Creek (Clifty) Plants, to assess the physical and operational condition of the plants through the year 2025. URS reviewed OVEC supplied data and visited both plants in August 2005. Following are the major conclusions of the review:

Ability of Plants to Operate As Planned

Each unit has been operating primarily in a base loaded mode with recent forced outage rates of less than 5% at Kyger and 7.4% to 8.6% at Clifty. The overall system produced a low of 14.49 GWhours in 2003 (negatively effected by long planned outages to install SCRs), to a maximum of 16.39 GWhours in 2004. The 2005 production is on track to exceed 2004 production. Twenty-year budget projections are based on 15.6 to 15.8 GWhours per year through 2009. As the FGD scrubbers are added in 2009 and 2010, the auxiliary power usage is assumed to increase by 2% of total plant generation, resulting in 15.2 GWhours per year from 2010 through 2025 The OVEC system appears capable of producing to the planned production levels.

Adequacy Of Projected Capital and Operating Costs

Through 2009, projected plant performance appears reasonable and the budget projections appear capable of supporting this continued operation.

With the installation and operation of the scrubbers in 2009, the long term projections of generation output, operations and maintenance costs, fuel costs and capital equipment costs appear realistic. However, there is some uncertainty since the equipment is in the process of being specified. OVEC needs to manage projected O&M costs as they purchase equipment and perform the detailed design. No alternative case projections have been presented to URS.

Environmental Compliance, Present and Future

The installation of the SCRs in 2002 and 2003 has reduced NOx emissions to less than required levels. As of January 1, 2009, the SCRs will operate 12 months a year, instead of the five month "ozone season", further reducing the levels of NOx emitted.

Wet Flue Gas Desulphurization (FGD) units are planned for installation on all eleven units to meet January 1, 2010 regulations. Modifications will be necessary to the ash ponds, stacks and ID fans. The installed cost of $665mm is included in the budget, as well as $24mm per year additional to the O&M budget.

With the Electrostatic Precipitators (ESP) installed on each unit in the late 1970's and the current stack performance, particulate emissions are also less than regulatory limits. No significant changes are anticipated except as may be related to the installation of the FGD systems.

Mercury control is federally mandated to be implemented in two phases through the year 2018. The exact level of mercury reduction at each plant will be set by the States of Ohio and Indiana. OVEC is working with the states, performing tests on mercury oxidation at their plants, and monitoring industry research on mercury control. Currently OVEC believes that the co-benefit of the FGD and SCR systems will achieve regulatory required mercury control for Phase 1. Phase 2 mercury control is more indefinite and may include activated carbon injection, or other control methods.

The ammonia on demand system (AOD), which supplies ammonia to the SCRs, is working adequately.

OVEC is complying with all federal and state regulations on water quality. Changes may be required in the future, but their cost impact is considered minimal.

OVEC has minimized its use and generation of hazardous wastes, and no significant cost impacts are expected due to hazardous wastes.

OVEC is removing underground fuel oil storage tanks and replacing them with above ground tanks. This is an attempt to avoid groundwater contamination, but there is still a risk of groundwater contamination that will have to be monitored over the life of the plant, and clean-up costs until these new tanks are installed and the old tanks are successfully cleaned.

URS believes that OVEC is doing an excellent job in their existing and planned environmental compliance strategy.

Good Engineering Practices

OVEC actively monitors their plant production, operations, maintenance, forced outages, emissions and costs. Management uses this data to identify trends and developing problems. With the advantage of eleven units of the same age and nearly identical design, when degradation at one unit is observed and corrected, evaluation is performed of the need for modifications at the other ten units. Based on observations and plant production, URS believes that Kyger and Clifty plants are managed well for long term operation.

Expected Life Of Physical Assets And Major Risks To Life Expectancy

The current and planned inspection, maintenance and upgrades of the boiler, turbine-generator, boiler feed pumps and other major equipment is impressive. URS expects that these plants should be available for full operation over the next 20 years. There are always risks associated with these judgments and OVEC appears to be working effectively to minimize these risks.

Recognized risks that exist for OVEC, as well as most other United States coal fired electric generating plants include:

- Major unexpected equipment failures that are too expensive to repair. This includes minor damage that can cause major fires, such as a lube oil system failure.

- Units are converted to cyclic or load following operational mode. This would adversely effect remaining life of high temperature equipment, and risk more operational events that could damage equipment.
- Serious operational error that causes direct and collateral damage.
- Extended loss of reliable PRB coal that affects pollution control and production plans. Currently the reserve coal level is very low due to delivery problems. Adequate reserves are needed on site to avoid unusual coal blends, or reduced production to meet pollution regulations.
- Major new environmental or other regulatory requirements, such as an enhanced "new source review".
- Major shift in fuel prices and technologies, particularly in combination with onerous new environmental regulations. This possibility appears to be remote over the next 20 years of operation.

1.0 INTRODUCTION

1.1 SCOPE OF WORK

URS Corporation (URS) was retained to perform an independent technical review of the current condition and the operational and maintenance plans at the Ohio Valley Electric Corporation / Indiana – Kentucky Electric Corporation (OVEC) Kyger Creek Station ("Kyger") Units 1 through 5, and Clifty Creek Station Units 1 through 6. This review has been conducted to assess the financial viability of the plants through the year 2025.

A Life Expectancy Study was conducted by URS, Sirois Engineering & Consulting, Inc. and Stone & Webster, Inc. resulting in the Kyger Creek Life Expectancy Study Report, Rev. 2 issued March 26, 2004 and the Clifty Creek Life Expectancy Report, Rev. 2 issued March 26, 2004. The data for these reports was complete through November 30, 2002. This new study is intended to assess the actual operations, maintenance and capital improvements experience from Dec. 1, 2002 to July 31, 2005 in comparison to the 2004 report assumptions. A physical assessment has been made in 2005 of the condition of the units to confirm the quality of the previous assumptions. Lastly, expected changes in fuel, operations, regulations or other factors that would affect the long term physical and financial viability of the plant are discussed.

This report contains the following sections:
Section 1, Introduction, including Scope of Work, Methodology, Assumptions and References.

Section 2, Kyger Creek Plant Description, Review of Operations and Assessment of Plant Conditions with special attention paid to changes since November 2002.

Section 3, Clifty Creek, Plant Description, Review of Operations and Assessment of Plant Conditions with special attention paid to changes since November 2002.

Section 4, Environmental Compliance, reviews the system's compliance with current regulations, and the modifications that will be required to comply with scheduled changes in regulations.

Section 5, Review of System Operations Plans, reviews OVEC plans in critical operational areas as they may affect the reliability and financial performance of the plant over the next 20 years. Specific review areas include coal supply, equipment upgrades, performance goals, transmission adequacy, planned capital improvements and planned O&M

Section 6, Projected Life Expectancy provides a qualitative assessment of the condition of the plants compared with the assumptions based on the 2002 data.

Section 7, Review of Financial Data discusses URS's assessment of OVEC's financial information.

Section 8, Conclusions compiles the information from all of the above sections to evaluate adequacy of OVEC's plans to successfully operate the plants over the next twenty years. These include environmental compliance, implementation of good engineering, operational and maintenance practices, expected remaining life of critical equipment, and major risks to life expectancy.

1.2 METHODOLOGY

This report summarizes major capital expenditures, operational and maintenance history, and environmental history from December 2002 through July 2005, as supplied by OVEC. URS visited Clifty and Kyger Stations to clarify the OVEC data and perform a high level evaluation of the plant condition. Data and observations are compared to the information available from the March 2004 report to assess the plant performance versus the expected performance in the previous report. In addition, expected changes in fuel, known environmental regulation revisions, and other expected changes affecting plant performance are noted.

This report also provides a summary of our review and opinions regarding the following:

- Condition of Station Equipment
- Remaining Life Projection (physical and operational life)
- Operations & Maintenance Life Projection Requirement
- Capital Expenditure Projections
- Environmental issues
- OVEC's Budget Projections

The Technical Review is limited to the scope of work described above and does not include review of the following:

- FERC Requirements and State Ratemaking Requirements
- Debt parameters, IRR targets, capitalization, insurance, or tax issues.
- OVEC management and personnel issues
- Legal issues relating to contracts and power sales agreements
- Power market issues, regulatory (non-environmental) issues, credit issues
- Unknown future laws related to power plant operations and environmental regulations

URS conducted this analysis and prepared the report utilizing reasonable care and skill and applied methods consistent with normal industry practice. Our opinions are based on our experience and documentation provided to us by OVEC. The documents URS has relied upon are listed in Section 1.4.

The participants in this review are:
Jerry Hollinden, URS Senior Vice President, Power Business Sector
Dan Predpall, URS Vice President
Jack Fager, URS Vice President Energy Industries
Gerry May, URS Manager of Mechanical Integrity
Wayne Jones, URS Senior Project Manager
Marvin Raber, Raber Consulting, Inc.

1.3 ASSUMPTIONS

In the preparation of this report and in formulating the expressed opinions, URS has made certain assumptions with respect to physical condition of components that may exist or events that may occur in the future. If events or circumstances are different than currently forecasted then the budgets may be impacted. The O&M and capital expense projections, maintenance plans, and equipment inspection reports were developed by OVEC and reviewed by URS. Assessment of legal issues, such as assignment of contractual rights, and procedural issues related to permits and permit waivers is outside of URS's scope of work as Independent Technical Reviewer.

URS personnel conducted a site visit on August 15, 2005 at Clifty plant and August 17, 2005 at the Kyger plant. The plants were visually inspected for general condition and to understand the history and future operational plans. The information gathered was used to verify the condition of the major equipment as represented in the maintenance reports.

The following assumptions pertain to this study and its results:

a. The reports, "Kyger Creek Life Expectancy Study Report," Rev. 2, March 26, 2004 and "Clifty Creek Life Expectancy Study Report," Rev. 2, March 26, 2004 provide the baseline data and analysis for this 2005 report.

b. OVEC provided operation, maintenance, environmental and financial data; representing December 2002 through July 2005.

c. This review is based on operation through the year 2025.

d. OVEC operating and maintenance practices will continue as reported previously and are represented in OVEC's expected reliability and expected expenses over the next 20 years.

e. Major overhaul intervals will continue at 10 years for the HP turbine sections, 20 years for the G.E. LP turbine sections, and 13 to 15 years for the Westinghouse LP turbine sections.

f. Feedwater heaters will generally be replaced or retubed when tube pluggage exceeds ten percent, except as noted.

g. Balance of plant equipment will be "replaced-in-kind", except as noted.

h. Major replacements are timed to correspond with scheduled major overhauls.

i. All costs are estimated in nominal dollars.

j. For the boiler, the planned outages for inspection and routine maintenance will continue on an annual basis.

k. All eleven (11) Kyger and Clifty units are similar in design, equipment manufacturer, performance, operation and maintenance. Any known significant differences are noted throughout this report.

l. All five (5) Kyger Units are typical, except Unit 1 turbine generator, which is a GE, similar to turbine generators at Clifty Creek plant.

m. All six (6) Clifty Units are typical, except Unit 6 has a hot side precipitator and no SCR, compared to the other units having a cold side precipitator and SCR.

n. All of the units will continue to operate as base load units, and not converted to load following or cycling operation.

o. Balance of plant equipment including, but not limited to, heat exchangers, condensers, pumps, valves, intake structures, outflow structures, condensers, conveyors, barge unloading facility, stacks, SCRs, instrumentation, transformers, fire protection systems, ash ponds and critical piping at both plants will continue to be inspected periodically and maintained.

1.4 REFERENCES

Clifty Creek & Kyger Creek Combined Data and Industry Data:

1. OVEC spreadsheets: OVECPowerCost05-25 Revision 7-20-05.xls, OVECPower Cost05-25 Revision 8-22-05.xls, OVECPower Cost05-25 Revision 8-25-05.xls, OVECPower Cost05-25 Revision 9/8/05.xls, telephone conversations with Mr. John Brodt (OVEC Secretary Treasurer) 8/19/05 and 8/25/05.
2. Other spreadsheets from OVEC/IKEC giving yearly capital, fuel, and other data.
3. Energy Information Administration report: Assumptions to the Annual Energy Outlook 2005. April 2005.
4. EPA report: Multipollutant Emission Control Options for Coal-fired Power Plants, EPA 600/R -05/034, March 2005.
5. Evolution Markets LLC weekly emissions markets update, dated August 19, 2005.
6. Federal Reserve Bank of Philadelphia third quarter 2005 economic forecast survey, released August 15, 2005.
7. Energy Information Administration Report: Annual Energy Outlook 2005, Feb. 2005
8. Cover Letter, D.E. Jones to G. May
9. Environmental Data Filled in by OVEC in Request for Information, Independent Technical Review
10. Percent Availability, each unit, 2002 through June 30, 2005
11. Unit Outage Schedule through 2008
12. Planning Meeting Notes, OVEC –IKEC Maintenance, March 19, 2004
13. Planning Meeting Notes, OVEC –IKEC Maintenance, December 17, 2004
14. 2003 – 2005, Coal Purchases By Plant
15. 2004 – 2005 Maintenance Planning Package
16. E-Mail: Summary of Request For Information as completed by OVEC.
17. OVEC Billable Cost Summary, 2001, 2002, 2003 & 2004 & 2005 -2009
18. Projected Fuel Costs 2005 to 2009

19. Projected Inter-Company Power Agreement Billable Cost Summary 2005 through 2025

Kyger Creek Data:

20. Cover List of Data
21. Construction Work Orders, 2001-2005, Detailed with purchase orders, inspections, etc.
22. Gross And Net Demonstrated Capability Test Data, 2-10-2003
23. Gross And Net Demonstrated Capability Test Data, 2-2-2004
24. Gross And Net Demonstrated Capability Test Data, 2-21-2005
25. Generating Unit Outage Report, Kyger Units 1 thru 5
26. Forced Outages, Kyger, 2003 to 2005
27. Events By Equipment Cause Code, December 2002 to June 2005
28. Generation Summary 2002 to 2005
29. Monthly Report of Station Operation, December 2002 to June 2005
30. Weekly Operating Data, Week ending Dec. 4, 2002 through Week Ending July 20, 2005.
31. Memo: Unit 4 Boiler Feed Pump Test, R.M. Weaver to R.T. Smith, 1/13/05
32. Kyger Creek YTD Responsibility Reports, 2000 to 2004
33. Kyger Creek Forecast Responsibility Report, 2005 to 2009
34. Kyger Construction Budgets 2005 through 2007

Clifty Creek Data:

35. Cover List of Data, M.R. Wilson to G.H. May, 8-2-2005
36. Construction Work Orders, 2001-2005, Detailed with purchase orders, inspections, etc.
37. Gross And Net Demonstrated Capability Test Data, 2-11-2003
38. Gross And Net Demonstrated Capability Test Data, 1-14-2004
39. Gross And Net Demonstrated Capability Test Data, 2-17-2005
40. Generating Unit Outage Report, Clifty Units 1 thru 6
41. Forced Outages, Clifty, 2003 to 2005
42. Events By Equipment Cause Code, December 2002 to June 2005
43. Generation Summary 2002 to 2005
44. Monthly Report of Station Operation, December 2002 to June 2005
45. Weekly Operating Data, Week ending Dec. 4, 2002 through Week Ending July 20, 2005.
46. Clifty Creek YTD Responsibility Reports, 2000 to 2004
47. Clifty Creek Forecast Responsibility Report, 2005 to 2009
48. Clifty Construction Budgets 2005 through 2007

2.0 KYGER CREEK PLANT

2.1 PLANT DESCRIPTION

Kyger Creek Plant consists of five pulverized coal-fired steam electric generating units, each designed to produce a total of approximately 217 MWe guaranteed output. The units were commissioned in 1955. Each unit consists of one boiler and one steam turbine generator. Each unit shares common facilities such as water treatment, fuel handling and ash disposal facilities, main powerhouse building, maintenance shops, service building, warehouse, and the wastewater treatment facilities.

2.1.1 Boiler System

The five boilers are replicate units designed and manufactured by Babcock & Wilcox Company (B&W). See **Figure 2-1** for a typical side elevation of the Kyger Creek and Clifty Creek boilers. The boilers are natural circulation, balanced draft (converted after initial commissioning), wet bottom furnace, open-pass, single reheat type steam generators. **Table 2-1-1** provides additional boiler data. They were originally designed for operation with high sulfur Midwest bituminous coal; now the fuel supply is a blend of mid-sulfur bituminous coal and low-sulfur western sub-bituminous coal from the Powder River Basin (PRB).

The Station has no auxiliary boilers available for start-up purposes. Auxiliary electric power is available from the grid for starting one unit during a plant black-start condition. Once one unit has been started, the other units can then be started.

Boiler draft fans are provided on a 2 x 60 percent capacity basis for the forced draft and 1 x 100 percent for the induced draft systems, respectively. Adjustable speed drives were added to all FD and ID fans when the SCRs were installed. The FD fans have sufficient capacity. The ID fans are sufficient, but there is no excess capacity.

The boiler water chemistry is achieved using softened water with a RO unit and an equilibrium phosphate system using tri-sodium phosphate, which also incorporates the use of ammonia for pH control, and O_2 scavenging.

Since commissioning, the units were converted from pressurized operation to balanced draft, the flue gas recirculation system has been removed and electrostatic precipitators (ESP) have been installed on each unit. NOx reduction methods have been installed that are comprised of overfire air in 1995 - 1999, and retrofit of SCR systems in 2002 and 2003, on each unit. Low NOx burners have not been installed.

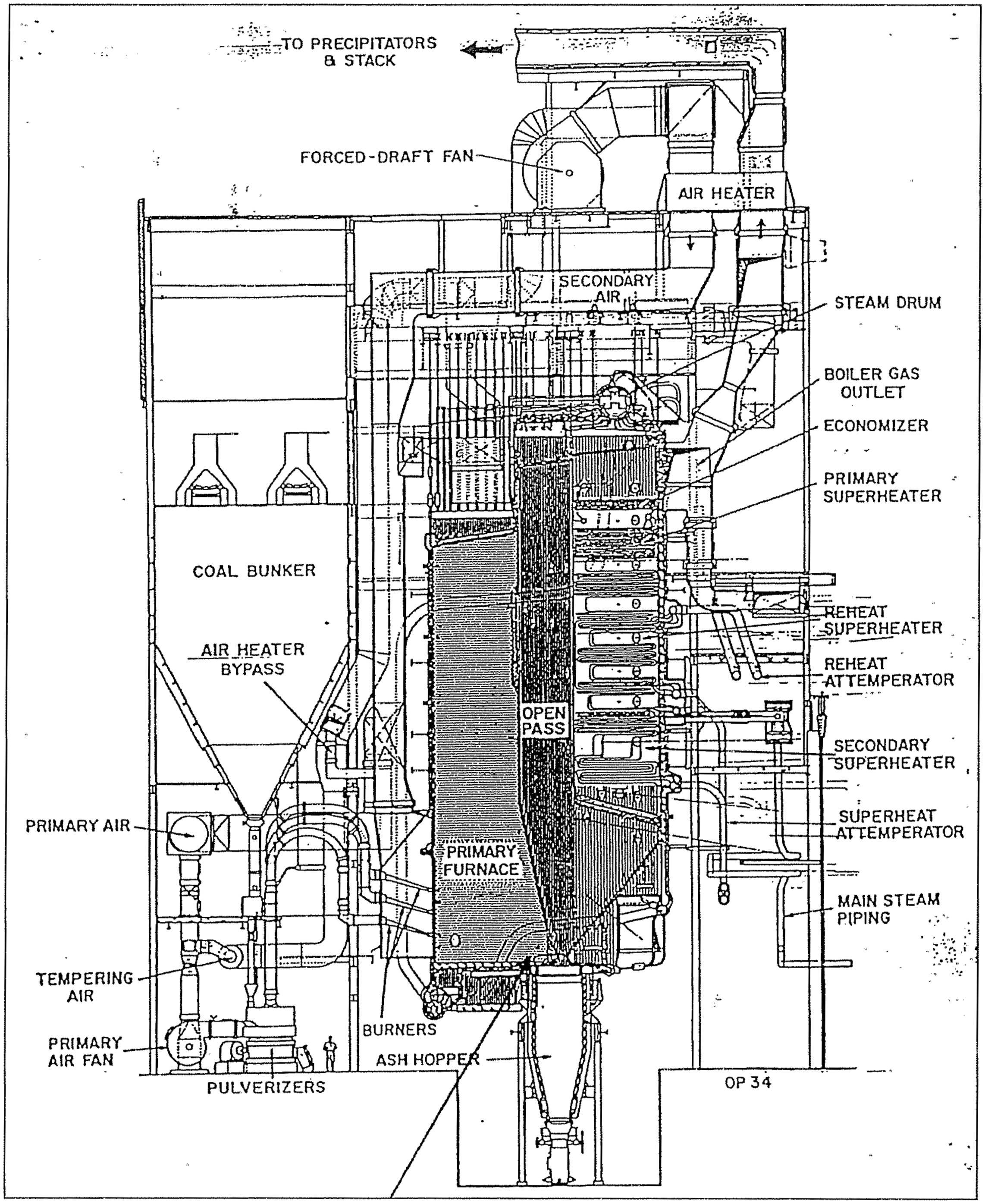

Figure 2-1 Kyger Creek & Clifty Creek Plants Boiler Side View

Table 2-1-1
Kyger Creek Plant Boiler Data

Item	Unit No. 1-5
Commercial Operation Year	1955
Manufacturer	Babcock & Wilcox Corp.
Type	Front Fired – Wet Bottom Furnace
Main Steam Temp (°F)	1,050
Reheat Steam Temp (°F)	1,050
Operating Pressure at SHO (psig)*	2,075
Design Pressure Rating (psig)	2,400
Main Steam Flow (lbs/hr)	1,336,000
Reheat Steam Flow (lbs/hr)	1,194,000
Circulation Type	Natural
Air Heater	Three Regenerative (Bisector Design)
Furnace Type	Single, wet bottom with open pass.
Pulverizer Type	7 – Babcock & Wilcox Model EL 70 Ball & Race Pulverizers
Primary Air	7 – centrifugal type motor driven hot PA fans
Additive System	Coal slag viscosity control done with magnetite injection
Burners	Directional flame burners on three rows on the front waterwall. No. 2 oil ignition.
Slag Blowers	31-Diamond Power with steam blowing medium
Furnace Draft	Balanced Draft
Forced Draft Fan	Two fans with original casings and wheels, blades and adjustable speed drives installed in 2002 and 2003.
Induced Draft Fan	One fan with original casing and new wheel, blade and Robicon adjustable speed drive installed in 2002 and 2003...
NO_x Control	All 5 units retrofitted with SCR system in 2002 and 2003.

* Unit operated at 2,000-psig throttle pressure

2.1.2 <u>Emission Control Systems</u>

2.1.2.1 General

The emission control system at Kyger Creek Plant consists of electrostatic precipitators for particulate emission control with the new SCR system for NO_x control. The plant does not have a flue gas desulphurization system for sulfur dioxide emission control.

2.1.2.2 Electrostatic Precipitators

The units were originally equipped with electrical / mechanical collectors. They were retrofitted with cold side electrostatic precipitators from Flakt Inc. during 1978-1980. Salient features of the precipitators are:

- Supplier - Flakt Inc.
- Flue Gas Flow Rate - 925,000 CFM
- Flue gas Inlet Temperature - 350°F
- Inlet Dust Loading - 0.5 – 3.5 grains/acf at 350°F
- Specific Collection Area. (SCA) - 336 (sq. ft./1000 acfm)
- Effective Collecting Area - 310,439 sq.ft.
- Length of Discharge Wire - 236,652 ft.
- T/R Sets Rating - 700 mA/55 kV/61 kVA
- Guaranteed Collection Efficiency- 99%
- Guaranteed Emission - 0.035 grain/acf (Maximum)

A flue gas conditioning (FGC) system was added in 1999 to augment precipitator performance. The FGC system was supplied by Wahlco Inc., and consists of sulfur burner, catalytic oxidation and sulfur trioxide injection grid and attendant controls. The overall ESP control system was upgraded in 1995-1996.

2.1.2.3 SCRs

The SCR systems were installed on all five units in 2002 and 2003 over the top of the turbine roof. ID fans were modified, and turbine bay structural columns were reinforced to support the additional weight.

- Supplier - Riley
- Catalyst Manufacturer - Argillon
- Catalyst Type - Plate
- Catalyst Specific Surface Area (m^2/m^3) - 353
- Plate Pitch (mm) - 5.6
- Plate Thickness (mm) - 0.8
- Plate Height (mm) - 625
- Catalyst Volume Per Unit (m^3)
    - Initial - 378.4
    - Full - 504.5
- Design Temperature (^{0}F) - 700
- Design Flow Rate (scfm) - 481,507
- Removal Efficiency - 90%

2.1.2.4 Stack

The original stacks were replaced with a single stack in 1980. All five units discharge through this approximately 990-ft. single stack. The stack consists of a concrete shell and a steel liner with attendant standard appurtenances such as rain hood (stainless steel), CEMS, access platforms, navigational lights and personnel elevator.

2.1.3 Turbine Generators

The Kyger Plant includes one General Electric and four Westinghouse turbine generators with the following characteristics:

Table 2-1-2
Kyger Creek Turbine Generator Details

Station	Manufacture	Nom. Size	Type	Steam Conditions	Age
Kyger Creek 1	GE	217,260 KWe	CC2F38	2,000 psig – 1050°/1050°F	50
Kyger Creek 2 – 5	Westinghouse	217,260 KWe	CC2F40	2,000 psig – 1050°/1050°F	50

The Unit 1 turbine-generator manufactured by General Electric is a cross-compound unit with the HP-IP (high-pressure and intermediate-pressure) turbine-generator operating at 3,600 RPM and the LP (low-pressure) turbine-generator consisting of two separate low-pressure turbines with 38-inch last stage blades operating at 1,800 RPM. The HP/IP and LP rotors are configured in opposed flow configuration.

This turbine was placed into service in 1955 and has a nominal rating of 217 MWe. Turbine design throttle conditions are 2,000 psig, 1,050°F main steam and 1,050°F reheat. Control valves are integral to the upper and lower half shells. The control valves are controlled by a mechanical hydraulic system (MHC). The unit control system is designed to operate in a combination of partial arc admission and full arc admission depending on whether the unit is in a startup mode, partial load or full load condition. During startup, the control valves are full open and steam is controlled by one upstream stop valve with a by-pass valve for admitting sufficient steam to carry approximately 20 percent load. The control valves then take control for partial arc admission mode. The units operate with sliding pressure down to approximately 500 PSIG in a load following mode. Main steam and reheat stop and intercept valves are separate from the turbine shells.

The unit 2-5' turbine-generators, manufactured by Westinghouse, are in a cross-compound arrangement. Separate HP (high-pressure) and IP (intermediate-pressure) turbines are arranged in a tandem compound arrangement and drive a generator at 3,600 RPM. The LP (low-pressure) turbine-generator consists of low-pressure turbine with 40-inch last stage blades. The LP turbine is an opposed flow configuration operating at 1,800 RPM. The HP, IP and LP rotors are opposed flow configuration to balance thrust.

The unit 2-5 turbine generators were placed into service in 1955 and have a nominal rating of 217 MWe. Turbine design throttle conditions are 2,000 psig, 1,050°F main steam and 1,050°F reheat. Plant personnel report the current main steam and reheat operating temperature is nominally 1025°F. Control valves, main steam and reheat stop and reheat intercept valves are separate from the turbine cylinders. The control valves are controlled by a mechanical hydraulic system (MHC). The unit control system is designed to operate in a combination of partial arc admission and full arc admission depending on whether the unit is in a startup mode, partial load or full load condition. During startup, the control valves are fully open and steam is controlled by one upstream stop valve with a by-pass valve for admitting sufficient steam to carry approximately 20 percent load. The control valves then take control for partial arc admission mode. The units can operate in sliding pressure mode down to approximately 500 psig in a load following mode.

2.1.4 Balance of Plant

The regenerative feedwater heating system consists of three LP heaters (1, 2, 3) arranged in series feeding a direct contact deaerating heater. The HP heater configuration consists of two parallel heater trains, each including three HP heaters (5 E&W, 6 E&W, 7 E&W). The condensate and feedwater pumps are horizontal, single speed motor driven type. There are 3 – 50% feedwater pumps and 2 – 100% condensate pumps.

The condensers are single pass, with Arsenical Copper tubes in Units 2 and 3, Alloy 194 Copper in Unit 1, and Alloy 706 Copper/Nickle in Units 4 and 5. They are directly cooled by Ohio River water provided by horizontal scroll case, low speed circulating water pumps. Two pumps and a condenser are provided for each unit.

The main steam piping is shown as seamless P22 and the hot reheat system piping as seamless P11 with welded elbows and a welded WYE fitting.

Each unit has three, single phase, three winding generator step up transformers. A winding is provided in each transformer for the HP generator, the LP generator and the high voltage.

2.2 REVIEW OF OPERATIONS

2.2.1 Operation Characteristics

Historically, the units are operated essentially in a base-load mode. However, in 2002 and part of 2003 the units operated in a daily load following mode. For the last two years, the units have been base loaded again. Planned outages, forced outages, de-rating for equipment repairs, and occasional environmental issues have caused less than full generation.

The load is reduced by throttling. Current operation with the coal blends and auxiliary equipment results in full generation at 1025^{0}F on the main steam and hot reheat systems, significantly less than the 1050^{0}F design temperature.

2.2.2 Operating Capability and Reliability

The Kyger units historically have, and presently each is, operated in approximately the same fashion and for the same duration. **Table 2-2-1** shows the total generation for each unit from 2001 through June 2005. Note that the total generation was greatest in 2004 at each unit over the 2001 to 2004 time span, and the 2005 production rates are on a track to nearly match 2004. (It is noted that at Clifty, all seven pulverizers must be operating to burn 80% PRB coal. At 60% PRB the plant can normally operate with six of the seven pulverizers. OVEC is aware of the potential of de-rating the power output if a pulverizer fails, and expects to avoid de-rating by properly maintaining the pulverizers before its Mean Time Between Failure (MTBF) of 25,000 hours, and by burning a lower percentage PRB if a failure occurs in between outages.

Table 2-2-1
Kyger Creek Plant Gross Power Generation Summary

Generation	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
2001MW-hrs	1,603,500	1,483,500	1,368,600	1,496,700	1,460,100
2002 MW-hrs	1,397,227	1,379,928	1,484,098	1,535,731	1,646,212
2003 MW-hrs	1,531,999	1,662,103	1,330,372	1,354,556	1,403,535
2004 MW-hrs	1,635,645	1,640,305	1,584,909	1,610,519	1,632,218
2005 MW-hrs (1st 6 months)	851,265	821,156	753,631	866,638	807,471

Table 2-2-2 contains annual plant production data. Given the relative similar operational characteristics of the individual units, URS determined that it was not necessary to analyze each unit for purposes of this evaluation. Station use is about 7% of gross generation. Load, Capacity and Capability Factors have all increased in 2004 and 2005 over the previous two years. Most importantly, the heat rate has also improved.

Table 2-2-2
Kyger Creek Plant Generation Statistics, 2002 to June 2005

Generation Description	2002	2003	2004	2005 (1st Half)
Plant Capacity (MW)	1086.3	1086.3	1086.3	1086.3
Plant Capability (MW)	1070.0	1070.0	1070.0	1070.0
Gross Generation (MWHR)	7,443,196	7,282,565	8,103,596	4,100,161
Station Use (MWHR)	591,077	548,277	578,529	286,210
Net Generation (MWHR)	6,852,119	6,734,288	7,525.067	3,813,951
Plant Load Factor (%)	73.65	74.58	80.67	83.30
Plant Capacity Factor (%)	78.22	76.55	84.93	86.89
Plant Capability Factor (%)	73.10	71.87	80.06	82.05
Coal Burned in Boilers (Tons)	2,760,922	2,787,089	3,119,367	1,600,279
BTU/Pound Coal (BTU/lb)	12,451	12,057	11,858	11,483
BTU / KWHR Net Generation	10,042	9,993	9,837	9,642

At Kyger, the availability of each unit for the past 5.5 years, excluding outages attributed to install SCR pollution abatement equipment in late 2002 through 2003, has not been less than 85 percent, and routinely well over 90 percent as shown in **Table 2-2-3**. (Note the 83.9% availability for Unit 3 in 2005 is primarily attributed to the planned outage of 22 days. It is assumed that operation during the second half of 2005 will raise the annual availability to 90%). The Availability Factor has been relatively stable before and after the SCR installation, indicating this major revamp has not negatively impacted availability. This overall plant availability, excluding SCR installation years, is greater than the North American Electric Reliability Council Average Availability Factor for 200 to 299 MW coal fired units of 87.49%

Table 2-2-3
Kyger Creek Annual Unit Availability Factor (%) – 2000 to 2005

Unit No.	2000	2001	2002	2003	2004	2005 (partial)
1	92.3	92.4	79.2 (SCR)	90.0	92.6	93.0
2	91.3	89.3	82.2 (SCR)	98.5	89.0	88.3
3	95.8	85.8	86.5	81.8(SCR)	90.2	83.9
4	90.9	92.0	91.3	83.8(SCR)	89.2	92.8
5	92.2	87.0	97.4	84.6(SCR)	93.9	90.5

The units are tested annually for gross and net capability. **Table 2-2-4** shows the values in Net Generation since 2000, except for 2002. There is no indication of any reduction in capability in any of the units and in fact the 2005 test results are higher than any of the results in recent years.

Table 2-2-4
Kyger Creek Net Generation Capability History

	Annual Avg. Established Capability		ECAR 8 - Hour Test		
Unit	**2000**	**2001**	**2003**	**2004**	**2005**
1	212	214	220	219	217
2	206	204	211	210	215
3	207	206	206	205	207
4	205	202	206	207	214
5	208	209	204	206	207
Plant Total	1038	1035	1047	1047	1060

Plant actual production data indicates that the Kyger units can generate approximately 240 gross MWe each during the winter months and about 220 gross MWe during the summer months. Auxiliary loss is about 17 MWe per unit, and is consistent throughout the year.

Forced outages are an indicator of the unit condition. **Table 2-2-5** shows the annual forced outage rate for the Kyger Plant. The values for 2000, 2001 and 2002 are from the 2004 report. The values for 2003, 2004 and 2005 were compiled by URS for each unit based on OVEC supplied data.

The average forced outage rate for the overall plant was 3.8% for 2003 and 2004. The rate has increased in the first half of 2005 due to a limited number of failures in Units 1, 3 & 4. This higher rate is probably a statistical anomaly due to the short averaging time. Even with these incidents the outage rate is still within historical and industry acceptable bands. The 1999 to 2003 average Forced Outage Rate for 200 to 299 MW coal fired plant according to NAERC was 4.44%. The vast majority of forced outage (FO) events and down time at Kyger is attributed to boiler problems, primarily tube failures. Of the overall 3.8% outage rate since January 2003, 3.15% is attributed to boiler problems. Of great significance is that electrical transformers, turbine-generators and aging plant auxiliary equipment are performing extremely well with very few failures and with limited down times when there is a failure.

Table 2-2-5
Kyger Creek Forced Outage Rate (%)

Year	All 5 Units	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
2000	3.38	2.78	3.60	4.15	4.50	1.79
2001	5.41	2.77	4.81	10.70	3.61	5.24
2002	4.17	6.13	5.29	4.39	3.29	2.24
2003	3.81	5.38	1.07	7.09	3.89	1.82
2004	3.82	3.05	4.76	5.05	4.31	1.95
2005 (thru June)	4.77	7.0	3.06	4.54	7.21	1.58

Accounting for both forced and planned outages these statistics demonstrate that unit age and usage has not diminished the capability of each unit to reliably generate electric power at near rated load for extended periods.

2.2.3 Fuel Sourcing

Since original commissioning, Kyger's fuel source has changed from high sulfur bituminous to a combination of bituminous and PRB sub-bituminous coals to meet operational requirements and air emission limits.

Coal is supplied from up to 10 different suppliers. In 2005, coal has been supplied from 23 different mines. The present trend is to utilize both the spot and long term markets for eastern coals. PRB coal is bought on long term contracts to provide as reliable a delivery as possible. American Electric Power (AEP) provides the fuel sourcing.

Coal is purchased on the basis of \$/unit of SO_2, with the plant 30 day rolling weighted average limit being 8.2 lb SO2/million Btu. Coal delivery is by barge, and the on-site coal storage is nominally ~40 days. At Kyger the range of the higher heating value (HHV) is 11,500-13,600 Btu/lb for eastern coals. PRB coals are specified at 8800 Btu/lb.

At Kyger, there are no fly ash sales. However this may change when the percentage of PRB is increased over 60%. The furnace bottom ash is used for various purposes off-site and is mined from the pond by a local company.

The use of PRB has increased each year since 2001 with the current blend approximately 30% PRB. Because the SCRs increase the SO2 to SO3 conversion rate, Kyger burns a lower sulfur blend during the ozone control period to reduce SO3 emissions.

Table 2-2-6 shows the average of the coal content since January 2003. Heat capacity and sulfur content have been reduced in the past 1-1/2 years. The reserve margin of coal in the pile has decreased from the beginning of 2003, particularly during the 2004 reporting period. At the end of 2004, there was only 2 weeks supply in storage, with approximately 4 weeks supply at the end of June, 2005.

Table 2-2-6
Kyger Creek Coal Purchases & Use, 2003 to 2005

Description	2003	2004	2005
Coal Burned (tons)	2,787,089	3,119,367	1,600,279
Coal Purchased (tons)	2,505,788	2,943,681	1,624,984
Coal In Storage (tons)	489,605*	121,178**	244,168***
Net Heating Value (BTU/lb)	12,414	11,962	11,772
Moisture (%)	9.92	11.43	11.33
Ash (%)	7.29	7.53	8.54
Sulfur (%)	1.30	1.20	1.16
SO2 (lb/mmBTU)	2.12	1.89	1.97

* Dec 4, 2002
** Dec 29, 2004
*** June 29, 2005

2.3 OBSERVATIONS OF PLANT CONDITIONS

2.3.1 Summary of 2004 Report On Plant Conditions

The following paragraphs are direct quotes from the 2004 report.

"URS Consultants walked-down one unit (Unit 2) from the top to the ground floor. In general the unit was found to be well maintained with most of the boiler components in a condition similar to other coal fired units of this vintage inspected by URS. The Kyger Plant conservative design and configuration is typical of a multi-unit pulverized coal-fired configuration. This includes a semi-indoor plant fueled through a common, covered coal gallery for the five units. The building is considered a common facility. Given its physical age, the visual condition of Kyger appeared to be very good for this vintage of power plant. There were no obvious signs of deteriorating structures, decking, support steel, piping, thermal insulation, cable trays, etc. "

"Planned outages, normally lasting at least two weeks, are done annually on each unit to monitor the respective unit condition, to repair crucial components and to do general boiler work. If a major project is previously scheduled, additional time is allotted to complete this project. Boiler chemical cleaning is done every 3 years. During the major outages, a significant amount of work is done on condition assessment and to repair and replace major components. The task of condition monitoring and project work planning is made easier since the boilers are replicates. Generally, what is required on one unit will eventually be required on all five units at Kyger at approximately the same time as the service profiles are very similar. This characteristic provides a major advantage in maintenance planning and budgeting.

System oversight by technical and engineering resources in Columbus provide synergy, as issues related to boiler safety, reliability and equipment/services purchasing is centralized and optimized. Further, this association provides the best current technical guidance available to assess plant component inspection and condition assessment as well as pollutant emission control technology issues.

OVEC/IKEC maintains well-documented programs for both capital and maintenance projects done at Kyger as demonstrated by the detailed listing of records available for review on this assignment. All of this is done consistent with FERC account format. Therefore, record keeping is well organized and referencing is optimized."

2.3.2 Capital Improvements, Maintenance & Inspection History Since 2002

Table 2-3-1 tabulates the Capital Improvements and Maintenance expenditure levels from January 2000 through June 2005. The capital expenses are dominated by the SCR installation in 2002 and 2003. The maintenance expenditure levels are reasonably consistent and trending upward. Plant personnel attribute this trend to the high number of long outages to install the SCRs. With the additional outage time, more maintenance was performed on the turbines, boilers and balance of plant equipment than is typically done. Overall, **Table 2-3-1** indicates a commitment by OVEC to maintain and improve the plants to meet the current requirements.

Table 2-3-1
Kyger Creek Summary of Total Capital and Maintenance Expenditure, 1997 - 2002

	Dollars					
CAPITAL	**2000**	**2001**	**2002**	**2003**	**2004**	**2005 (6 mo.)**
Boiler	565,229	7,871,735	696,577	182,943,726	10,514,791	176,111
Turbine Generator	2,402,603	NA	200,310	171,495	0	1,182,204
Accessory Equipment	NA	NA	NA	426,564	0	82,273
Miscellaneous Equipment	715,958	621,728	65,587	132,970	829,970	74,296
Total Capital	**3,683,790**	**8,493,463**	**962,474**	**183,674,755**	**11,344,761**	**1,514,884**
MAINT						
Boiler Plant	13,034,600	14,072,800	14,040,844	15,586,441	15,043,506	7,384,884
Electric Plant	4,467,136	3,458,050	2,324;209	4,512,419	4,877,436	1,013,471
Misc. Plant	463,156	325,229	308,121	378,047	499,975	190,477
Total Maintenance	**17,964,892**	**17,856,079**	**16,673,174**	**20,476,907**	**20,420,917**	**8,588,832**

The following sections summarize the significant improvements, repairs and inspections represented by the above expenditures.

2.3.2.1 Boiler

Boilers are chemically cleaned every 3 years. Typically the cleaning results in "uncovering" some tube leaks and additional repairs are required. Unit 2 was chemically cleaned in 2003 and Unit 5 in 2004.

Each boiler is inspected and repaired annually during a 14 day outage. Typical inspections include visual inspection of steam drum headers, tubes and supports, magnetic particle inspection of selected locations, replication, inspection for ligament cracking, and other standard NDE. Inspections are performed on a schedule and not all inspections are performed annually. Indications are consistently repaired at the time they are found.

All five reheater outlet header to hot reheat pipe nozzles have been replaced. The original design was a large pad which tended to crack at the pad welds. Each nozzle was replaced with a fitting (similar to a weldolet).

SCR units were installed in 2002 and 2003 on all five units. These units are located above the turbine roof. There were some change-outs of the original damper valves that are used for by-pass after the "ozone season".

Stainless steel overlays have been made on the water walls in the primary furnace over the past several years. Plant personnel believe this has reduced forced outages on the boiler.

Units 3, 4 & 5, Ash hopper skirts changed out in 2003.
Unit 5, 2004: Replaced bearing plates on slag blowers
Unit 5, 2004: Repaired convection pass
Unit 5, 2004: Inspected ash hopper and repaired defects.
Unit 5, 2004: Inspected and repaired Windbox & Primary Furnace

2.3.2.2 Turbine Generator

As noted above, the HP turbine components are on a 10 year major overhaul schedule and the L.P. sections on a 13 -15 year major overhaul schedule for the Westinghouse LP turbines, and 20 year major overhaul schedule for the G.E. LP turbine. Examinations are made annually during the boiler shutdowns. No unusual problems reported since 2002.

A spare HP, LP and IP rotor exists on site for the Westinghouse turbine generators. The General Electric spare rotors are maintained and stored at Clifty Creek since they have six GE units.

Unit 4, 2003: L.P., I.P. & H.P. Turbine Components inspected & repaired
Unit 2, 2004, L.P. and throttle and governor valve inspections

Unit 2, 2004, HP Exciter Reduction Changed Out
Unit 3, 2003 I.P. and throttle and governor valve inspections
Unit 3, 2003, HP Exciter Reduction Change Out
Unit 5, Repaired 26" long crack in Reheat Stop Valve

2.3.2.3 Emissions Control System

Selective Catalytic Reduction (SCR) systems were installed on all 5 boilers at Kyger in 2002 and 2003. Under the current regulations, SCR operation is required only during the "ozone season". It is anticipated that year round SCR operation will be required by January 2009. These systems are capable of continuous operation and this mode of operation would result only in the additional variable operating costs associated with increased consumption of ammonia and catalyst. All associated SCR equipment maintenance would increase proportionally to SCR operating hours. See Section 7.0 for a discussion of the budgeting of these costs.

Electrostatic Precipitators (ESP) were installed on all 5 Kyger units in the late 1970's. All 5 units are fitted with "cold side" ESP's. These units are located downstream of the air preheater. Recent maintenance of all ESP's have significantly improved operating performance. The ESP systems were originally designed for operation with eastern bituminous coals. Particulate control on all 5 units has consistently operated well below the current emission limit.

Flue Gas Desulphurization units (FGD) are not currently installed at Kyger. OVEC plans to install FGDs on all 5 units by January 1, 2010. Conceptual design is complete and detailed design has begun. A new stack is planned as part of the FGD retrofit. The plant is currently burning less than 30% PRB coal, and plans to increase the PRB to between 60% and 80% in 2006 in an effort to reduce SO2 emissions. Future SO2 emissions will be managed with the purchase of SO2 credits until the FGD systems are operational.

No mercury reduction systems are currently installed on any of the Kyger units, although preliminary plans are being considered for likely mercury reduction requirements.

During each available opportunity, forced or planned outage, the SCR is inspected for fly ash accumulation and cleaned if necessary.

CEMS and other monitoring systems are calibrated and maintained as necessary.

2.3.2.4 Stack

The Kyger stack is due for inspection. It appears that the problems found on the Clifty stacks are not present at Kyger. This opinion is based only on a cursory look and not a detailed inspection. The current plan is to replace the Kyger stack during the FGD installation in 2009.

2.3.2.5 Balance of Plant

All steel, concrete foundations, turbine generator pedestal and other structural components appear to be in good condition. When the SCRs were installed, columns in the T-G building were reinforced to support the increased loads.

Intake and outflow structures are periodically inspected and no significant deterioration. Zebra mussels have been an occasional problem to clean out, but they have not caused any de-rating or forced outages in the last 3 years.

Critical pipe and pipe supports are inspected annually and adjusted as needed.

Electrical cable deterioration has not been a problem.

Instrumentation and controls are continually being maintained and upgraded. The major upgrade in the control rooms to the Ovation system has been accepted by plant operators and the system is working properly.

Some other equipment that has been repaired since 2002 include:
Unit 4 and 5 Boiler Feed Pumps rebuilt during boiler outages
Unit 4 Feedwater Heater 47E retubed 2004
Unit 5 Feedwater Heater 56W retubed, 2004
Unit 4, Reheat Steam Line elbows inspected by MT.

2.3.2.6 Coal Supply

In July 2005 BNSF-UP joint line maintenance activities were limiting Powder River Basin coal deliveries. This is expected to be a temporary hindrance through fall 2005.

2.3.2.7 Transportation

Coal is delivered to plant by barge. No changes have been made in the dock, unloading facility and coal yard in the past three years.

2.3.2.8 Electricity Transmission

No recent changes have been made to the electrical transmission system from the plant to sponsoring companies. The system has been adequate, and OVEC has the responsibility for the transmission system.

3.0 CLIFTY CREEK PLANT

3.1 PLANT DESCRIPTION

Clifty Creek Station consists of six pulverized coal-fired steam electric generating units, each designed to produce a total of approximately 217 MWe guaranteed output. The units were commissioned in 1955 and 1956. Each unit consists of one boiler and one steam turbine generator. Each unit shares common facilities such as water treatment, fuel handling, ash disposal facilities, main powerhouse building, maintenance shops, service building, warehouse, and the wastewater treatment facilities.

3.1.1 Boiler System

The six boilers are replicate units designed and manufactured by Babcock & Wilcox Company (B&W). See **Figure 2-1** for a typical side elevation of the Clifty Creek boilers. The boilers are natural circulation, balanced draft (converted after initial commissioning), wet bottom furnace, open-pass, single reheat type steam generators. **Table 3-1-1** provides additional boiler data. They were originally designed for operation with high sulfur Midwest bituminous coal; now the fuel supply is a blend of mid-sulfur bituminous coal and low-sulfur western sub-bituminous coal from the Powder River Basin (PRB).

The Station has no auxiliary boilers available for start-up purposes. Auxiliary electric power is available from the grid for starting one unit during a plant black-start condition. Once one unit has been started, the other units can then be started.

Boiler draft fans are provided on a 2 x 60 percent capacity basis for the forced draft and 1 x 100 percent for the induced draft systems, respectively. Adjustable speed drives were added to all FD and ID fans when the SCRs were installed. The FD and ID fans are sufficient, but there is no excess capacity.

The boiler water chemistry is achieved using softened water with a RO unit and an equilibrium phosphate system using tri-sodium phosphate, which also incorporates the use of ammonia for pH control, and O_2 scavenging.

Since commissioning, the units were converted from pressurized operation to balanced draft, the flue gas recirculation system has been removed and electrostatic precipitators (ESP) have been installed on each unit, NOx reduction methods were installed that are comprised of overfire air in 1995 - 1999, burner modifications and retrofit of SCR systems in 2002 and 2003 on units 1 through 5.

Table 3-1-1
Clifty Creek Plant Boiler Data

Item	Unit No. 1-6
Commercial Operation Year	1955-1956
Manufacturer	Babcock & Wilcox Corp.
Type	Front Fired – Wet Bottom Furnace
Main Steam Temp (°F)	1,050
Reheat Steam Temp (°F)	1,050
Operating Pressure at SHO (psig)*	2,075
Design Pressure Rating (psig)	2,400
Main Steam Flow (lbs/hr)	1,336,000
Reheat Steam Flow (lbs/hr)	1,194,000
Circulation Type	Natural
Air Heater	Three Regenerative (Bisector Design)
Furnace Type	Single, wet bottom with open pass.
Pulverizer Type	7 – Babcock & Wilcox Model EL 70 Ball & Race Pulverizers
Primary Air	7 – centrifugal type motor driven hot PA fans
Additive System	Coal slag viscosity control done with iron ore injection
Burners	Directional flame burners on three rows on the front waterwall. No. 2 oil ignition.
Slag Blowers	53-Diamond Power with steam blowing medium
Furnace Draft	Balanced Draft
Forced Draft Fan	Two fans with original casings and new wheels, blades and adjustable speed drives installed in 2002 and 2003.
Induced Draft Fan	One fan with original casing and new wheel, blade and Robicon adjustable speed drive installed in 2002 and 2003...
NO_x Control	Units 1 through 5 retrofitted with SCR system in 2002 and 2003.

* Unit operated at 2,000-psig throttle pressure

3.1.2 Emission Control Systems

3.1.2.1 General

The emission control system at Clifty Creek Plant consists of electrostatic precipitators for particulate emission control with the new SCR system for NO_x control. The plant does not have a flue gas desulphurization system for sulfur dioxide emission control.

3.1.2.2 Electrostatic Precipitators

The units were originally equipped with mechanical collectors. Units 1 through 5 were retrofitted with cold side electrostatic precipitators from Lodge Cottrell in 1978 & 1979. Unit 6 was retrofitted with a hot –side precipitator from Western Precipitator in 1977. Salient features of the precipitators are:

Cold-Side Precipitators (Units 1 through 5)

- Supplier - Lodge Cottrell
- Flue Gas Flow Rate - Design 925,000 CFM
- Flue gas Inlet Temperature - 350°F
- Inlet Dust Loading - 0.27 – 3.7 grains/acf at 350°F
- Specific Collection Area. (SCA) - 532 (sq. ft./1000 acfm)
- Effective Collecting Area - 492,480 sq.ft.
- Length of Discharge Wire - 316,000 ft.
- T/R Sets Rating - 1000 mA/55 kV/61 kVA
- Guaranteed Collection Efficiency - 98.41%
- Guaranteed Emission - 0.05 grain/acf (Maximum)

Hot-Side Precipitator (Unit 6)

- Supplier - Western Precipitators
- Gas Flow Rate - 1,303,000 acfm
- Flue Gas Inlet Temperature - 760°F
- Inlet Dust Loading - 0.37 to 3.4 grains/acf
- Specific Collection Area (SCA) - 371 (sq. ft./1,000 acfm)
- Effective Collection Area - 483,413 sq. ft.
- T/R Sets Rating - 1,000 mA/45 kV DC
- Guaranteed Collection Efficiency - 99.4%
- Emission - 0.0045 grain/acf

A flue gas conditioning (FGC) system was added in 1999 on units 1 through 5 to augment precipitator performance. The FGC system was supplied by Wahlco Inc., and consists of sulfur burner, catalytic oxidation and sulfur trioxide injection grid and attendant controls. The overall ESP control system was upgraded in 1997 & 1998.

3.1.2.3 SCR

The SCR systems were installed on units 1 through 5 in 2002 and 2003 over the top of turbine roof. ID fans were modified, and turbine bay structural columns were reinforced to support the additional weight.

- Supplier - Riley
- Catalyst Manufacturer - Argillon
- Catalyst Type - Plate
- Catalyst Specific Surface Area (m^2/m^3) - 353

- Plate Pitch (mm) - 5.6
- Plate Thickness (mm) - 0.8
- Plate Height (mm) - 625
- Catalyst Volume Per Unit (m^3)
    - Initial - 378.4
    - Full - 504.5
- Design Temperature (^0F) - 725
- Design Flow Rate (scfm) - 443,617
- Removal Efficiency - 90%

3.1.2.4 Stack

The original stacks were replaced with a two stacks in 1978 and 1979. Units 1 through 3 discharge through one stack and units 4 through 6 discharge through the other. The stacks consist of a concrete shell and a steel liner with attendant standard appurtenances such as rain hood (stainless steel), CEMS, access platforms, navigational lights and personnel elevator.

3.1.3 Turbine Generators

The Clifty Creek station includes six General Electric turbine generators with the following characteristics:

Table 3-1-2
Clifty Creek Plant Turbine Generator Details

Units	Manufacture	Nom. Size	Type	Steam Conditions	Age
Units 1 through 6	GE	217,260 KWe	CC2F38	2,000 psig - 1050°/1050°F	50

These turbine-generators manufactured by General Electric are cross-compound units with the HP-IP (high-pressure and intermediate-pressure) turbine-generator operating at 3,600 RPM and the LP (low-pressure) turbine-generator consisting of two separate low-pressure turbines with 38-inch last stage blades operating at 1,800 RPM. The HP/IP and LP rotors are configured in opposed flow configuration.

The turbines were placed into service in 1955 and 1956 and have a nominal rating of 217 MWe. Turbine design throttle conditions are 2,000 psig, 1,050°F main steam and 1,050°F reheat. Control valves are integral to the upper and lower half shells. The control valves are controlled by a mechanical hydraulic system (MHC). The unit control system is designed to operate in a combination of partial arc admission and full arc admission depending on whether the unit is in a startup mode, partial load or full load condition. During startup, the control valves are full open and steam is controlled by one upstream stop valve with a by-pass valve for admitting sufficient steam to carry approximately 20 percent load. The control valves then take control for partial arc admission mode. The units operate with sliding pressure down to approximately 500 psig in a load following mode. Main steam and reheat stop and intercept valves are separate from the turbine shells.

3.1.4 Balance of Plant

The regenerative feedwater heating system consists of three LP heaters (4th, 6th and 8th stage heaters) arranged in series feeding a direct contact deaerating heater. The HP heater configuration consists of two parallel heater trains, each including three HP heaters (HP, N&S, IP, N&S and XS {crossover} N&S). The condensate and feedwater pumps are horizontal, single speed motor driven. There are 3 - 50% boiler feed pumps, and 2 – 100% condensate pumps.

The condensers are single pass, with 90/10 copper / nickel tubes, directly cooled by Ohio River water provided by horizontal scroll case, low speed circulating water pumps. Two pumps and a condenser is provided for each unit.

The main steam piping is shown as seamless P22 and the hot reheat system piping as seamless P11. None of this pipe, fittings or headers are seam welded.

Each unit has three, single phase, three winding generator step up transformers. A winding is provided in each transformer for the HP generator, the LP generator and the high voltage.

3.2 REVIEW OF OPERATIONS

3.2.1 Operation Characteristics

Historically, the units are operated essentially in a base-load mode. However, in 2002 and part of 2003 the units operated in a daily load following mode. For the last two years, the units have been base loaded again. Planned outages, forced outages, de-rating for equipment repairs, and occasional environmental issues have caused less than full generation.

The load is reduced by throttling. Current operation with the coal blends and auxiliary equipment results in full generation at 1040^0F on the main steam and hot reheat systems, slightly less than the 1050^0F design temperature.

3.2.2 Operating Capability and Reliability

The Clifty units historically have, and presently each is, operated in approximately the same fashion and for the same duration. **Table 3-2-1** shows the total generation for each unit from 2001 through June 2005. Except for Unit 2, the 2005 production rates are on pace to exceed 2004. It is noted that all seven pulverizers must be operating to burn 80% PRB coal. At 60% PRB the plant can normally operate with six of the seven pulverizers. Thus changes in PRB may cause operational load to be de-rated more often. OVEC is aware of the potential of de-rating the power output if a pulverizer fails, and expects to avoid de-rating by properly maintaining the pulverizers before its Mean Time Between Failure (MTBF) of 25,000 hours, and by burning a lower percentage PRB if a failure occurs inbetween outages.

Table 3-2-1
Clifty Creek Gross Power Generation Summary

Generation	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
2001MW-hrs	1,221,000	1,381,000	1,272,500	1,424,100	1,407,000	1,324,000
2002 MW-hrs	1,476,725	1,483,852	1,482,974	1,313,904	1,209,748	1,545,399
2003 MW-hrs	1,294,662	1,255,895	1,080,526	1,378,849	1,537,026	1,265,466
2004 MW-hrs	1,513,087	1,503,778	1,539,940	1,576,720	1,314,804	1,502,822
2005 MW-hrs (1st 6 mo.)	797,609	447,088	886,913	782,783	732,808	857,191

Table 3-2-2 contains annual plant production data. Given the relative similar operational characteristics of the individual units, URS determined that it was not necessary to analyze each unit for purposes of this evaluation. Station electrical use is about 7.5% of gross generation. Load, Capacity and Capability Factors have all increased in 2004 and 2005 over the previous two years. Most importantly, the heat rate has also improved.

Table 3-2-2
Clifty Creek Plant Generation Statistics, 2002 to June 2005

Generation Description	2002	2003	2004	2005 (1st Half)
Plant Capacity (MW)	1,303.56	1,303.56	1,303.56	1,303.56
Plant Capability (MW)	1,284	1,284	1,284	1,284
Gross Generation (MWHR)	8,512,602	7,812,494	8,951,151	4,534,332
Station Use (MWHR)	673,790	605,559	665,753	328,317
Net Generation (MWHR)	7,838,812	7,206,935	8,285,398	4,206,015
Plant Load Factor (%)	70.02	67.00	73.63	75.29
Plant Capacity Factor (%)	74.55	68.42	78.17	80.07
Plant Capability Factor (%)	69.69	64.07	73.46	75.41
Coal Burned in Boilers (Tons)	4,110,104	3,878,511	4,401,922	2,106,710
BTU/Pound Coal (BTU/lb)	9,731	9,652	9,691	10,076
BTU / KWHR Net Generation	10,209	10,386	10,292	9,862

At Clifty, the overall availability for the past 5.5 years has varied from 80.5% to 89.0%. See **Table 3-2-3** the low availability in 2003 is attributed to installation of SCRs and some forced outages on Units 1 and 3. The overall plant availability in 2004 and 2005 remains on the lower end of the recent performance range. The average availability of 200 to 299 MW coal fired power plants from 1999 to 2003 is 87.49%, according to the North American Electric Reliability Council.

Table 3-2-3
Clifty Creek Annual Unit Availability (%) – 2000 to 2005

Unit No.	2000	2001	2002	2003	2004	2005 (1st half)
1	89.7	81.0	90.5	76.8 (SCR)	82.5	87.2
2	91.5	89.0	90.3	79.1 (SCR)	84.8	53.3
3	89.8	86.0	91.8	65.5 (SCR)	85.3	96.8
4	87.3	92.5	83.8 (SCR)	85.7	89.6	84.3
5	90.7	90.8	75.3 (SCR)	94.4	76.1	80.1
6	85.1	87.7	95.7	81.7	90.8	95.6
Total	89.0	87.8	87.9	80.5	84.9	82.9

The units are tested annually for gross and net capability. **Table 3-2-4** shows the values in Net Generation since 2000, except for 2002. There is no indication of any reduction in capability in any of the units and in fact the 2004 and 2005 test results are higher than any of the results in the previous 3 years.

Table 3-2-4
Clifty Creek Net Generation Capability History

	Annual Avg. Established Capability		ECAR 8-Hour Test		
Unit	**2000**	**2001**	**2003**	**2004**	**2005**
1	208	208	216	218	223
2	209	203	209	214	211
3	205	199	213	213	216
4	205	203	218	218	217
5	215	212	220	215	213
6	204	204	201	213	211
Plant Total	1246	1229	1277	1291	1291

Plant actual production data indicates that the Clifty units can generate approximately 240 gross MWe each during the winter months and about 220 gross MWe during the summer months. Auxiliary loss is about 17 MWe per unit, and is consistent throughout the year.

Forced outages are an indicator of the unit condition. **Table 3-2-5** shows the annual forced outage rate for the Clifty Plant.

The average forced outage rate for the overall plant has been 8.5% in 2003 and 2004, with a reduction to 7.4% the first six months of 2005. This is significantly greater than the 2000 to 2002 rates and also greater than the North American Electric Reliability Council average Forced Outage Rate of 4.4% from 199 to 2003 at coal fired plants between 200 and 299 MW The vast majority of forced outage (FO) events and down time at Clifty is attributed to boiler problems, primarily tube failures. Of the overall 8.5% outage rate since January 2003, approximately 2/3 is attributed to boiler problems. The turbine generator rate is 1/5 of the total forced outage time, primarily attributed to the 2003 outage on Unit 3 in 2003 when an instrumentation failure led to overheating.

Ash pluggage of the SCRs has occurred a few times requiring cleaning time of up to 10 days. This level of pluggage has not occurred in the past 18 months.

Of great significance is that electrical transformers and aging plant auxiliary equipment are performing extremely well with very few failures and with limited down times when there is a failure.

Table 3-2-5
Clifty Creek Forced Outage Rate (%)

Year	All 6 Units	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6
2000	6.37	5.24	8.18	4.73	8.13	3.65	8.21
2001	5.87	4.84	5.1	10.91	3.74	3.99	6.55
2002	2.74	4.21	3.07	2.76	2.00	4.73	0.00
2003	8.41	10.51	7.70	19.87	3.20	4.85	5.64
2004	8.57	11.25	9.05	9.71	6.11	10.09	5.49
2005 (thru June)	7.40	12.76	8.33	3.19	9.87	9.35	1.51

3.2.3 Fuel Sourcing

Since original commissioning, Clifty's fuel source has changed from high sulfur bituminous to a combination of bituminous and PRB sub-bituminous coals to meet operational requirements and air emission limits. Clifty has a dry fly ash handling system that allows the maximum PRB blend to approx. 75% without incurring pulverizer capacity limits. The sulfur dioxide emission ranges from 0.5 to 1.6 lb/mmBtu.

Coal is supplied from up to 8 different suppliers. The present trend is to utilize both the spot and long term markets for Eastern coal. PRB coal is bought on long term contracts to provide as reliable a delivery as possible. American Electric Power (AEP) provides fuel procurement services.

Coal is purchased on the basis of $/unit of SO_2, with the 30 day rolling weighted average limit being 7.52 lb/million Btu. Coal delivery is by barge, and the on-site coal storage is targeted for ~40 days. At Clifty the range of the higher heating value (HHV) is 9,500-10,200 Btu/lb, which signifies a much higher fraction of PRB use. Because of the higher PRB fraction being used the pulverizers are outfitted with a steam inerting system as protection against potential fires and explosions.

At Clifty, there are fly ash sales for concrete admixtures as the ash handling is a dry type.

Table 3-2-6 shows the average coal content since January 2003. The coal characteristics on average have been relatively consistent over the 3 year period, although sulfur content was lowest in 2003. The reserve margin of coal in the pile has decreased from the beginning of 2003, particularly during the 2004 reporting period. At the end of 2004, there was only 26 days supply in storage and of that only 6.4 days of western coal in storage. By mid-2005, there was about 2 weeks supply of western coal and 3 weeks supply of eastern coal in storage.

Table 3-2-6
Clifty Creek Coal Purchases & Use, 2003 to 2005

Description	2003	2004	2005
Coal Burned (tons)	3,878,511	4,401,922	2,106,710
Coal Purchased (tons)	3,502,451	3,802,317	2,357,831
Coal In Storage (tons)	744,182*	313,777**	224,749***
Net Heating Value (BTU/lb)	10,017	10,046	10,122
Moisture (%)	21.44	20.23	20.33
Ash (%)	5.44	5.93	5.85
Sulfur (%)	0.51	.85	.77
SO2 (lb/mmBTU)	0.91	1.46	1.52

* Dec 4, 2002
** Dec 29, 2004
*** June 29, 2005

3.3 OBSERVATIONS OF PLANT CONDITIONS

3.3.1 Summary of 2004 Report On Plant Conditions

The following paragraphs are direct quotes from the 2004 report.

"URS Consultants walked-down one boiler (Unit 4) from the top to the ground floor. In general the unit was found to be well maintained with most of the boiler components in a condition similar to other coal fired units of this vintage inspected by URS. The Clifty Plant conservative design and configuration is typical of a multi-unit pulverized coal-fired configuration. This includes a semi-indoor plant fueled through a common, covered coal gallery for the six units. The building is considered a common facility. Given its physical age, the visual condition of Clifty appeared to be very good for this vintage of power plant. There were no obvious signs of deteriorating structures, decking, support steel, piping, thermal insulation, cable trays, etc. "

"Planned outages, normally lasting at least two weeks, are done annually on each unit to monitor the respective unit condition, to repair crucial components and to do general boiler work. If a major project is previously scheduled, additional time is allotted to complete this project. Boiler chemical cleaning is done every 3 years. During the major outages, a significant amount of work is done on condition assessment and to repair and replace major components. The task of condition monitoring and project work planning is made easier since the boilers are replicates. Generally, what is required on one unit will eventually be required on all six units at Clifty at approximately the same time as the service profiles are very similar. This characteristic provides a major advantage in maintenance planning and budgeting.

System oversight by technical and engineering resources in Columbus provide synergy, as issues related to boiler safety, reliability and equipment/services purchasing is centralized and optimized. Further, this association provides the best current technical guidance available to assess plant component inspection and condition assessment as well as pollutant emission control technology issues.

OVEC/IKEC maintains well-documented programs for both capital and maintenance projects done at Clifty as demonstrated by the detailed listing of records available for review on this assignment. All of this is done consistent with NAERC account format. Therefore, record keeping is well organized and referencing is optimized."

3.3.2 Capital Improvements, Maintenance & Inspection History Since 2002

Table 3-3-1 tabulates the Capital Improvements and Maintenance expenditures from January 2000 through June 2005. The capital expenses are dominated by the SCR installation in 2003. The maintenance expenditures are reasonably consistent and trending upward. This is expected as units age and because of the installation of the SCRs. The maintenance requirements are expected to increase as aged equipment must be repaired or replaced. Overall, Table 4-1 indicates a commitment by OVEC to maintain and improve the plants to meet the current requirements.

Table 3-3-1
Clifty Creek Summary of Total Capital and Maintenance Expenditure, 2000 - 2005

	Dollars					
CAPITAL	**2000**	**2001**	**2002**	**2003**	**2004**	**2005 (1st 6 mo.)**
Boiler	3,007,784	2,627,934	499,678	169,833,312	13,455,914	2,433,133
Turbine Generator	64,028	1,261,610	317,500	134,636	349,881	2,449,242
Accessory Equipment	423,536	59,353	266,950	449,471	272,696	NA
Miscellaneous Equipment	383,141	732,180	18,658	314,215	734,270	650,615
Total Capital	**3,878,489**	**4,681,077**	**1,102,786**	**170,731,634**	**14,812,761**	**5,532,990**
MAINT						
Boiler Plant	11,216,023	11,606,076	13,562,099	16,275,026	17,897,669	8,666,790
Electric Plant	2,529,112	4,184,859	3,096,525	6,445,083	5,216,848	3,640,747
Misc. Plant	709,251	608,421	900,778	848,734	808,071	355,214
Total Maint.	**14,454,386**	**16,399,356**	**17,559,402**	**23,568,843**	**23,922,588**	**12,662,751**

The following sections are a summary of the significant improvements, repairs and inspections represented by the above expenditures.

3.3.2.1 Boiler

Boilers are chemically cleaned every 3 years. Typically the cleaning results in "uncovering" some tube leaks and additional repairs are required.

Each boiler is inspected and repaired annually during a 14 day outage. Typical inspections include visual inspection of steam drum headers, tubes and supports, magnetic particle inspection of selected locations, replication, inspection for ligament cracking, and other standard NDE. Inspections are performed on a schedule and not all inspections are performed annually. Indications are consistently repaired at the time they are found.

SCR units were installed in 2002 and 2003 on units 1 through 5. These units are located above the turbine roof. There were some change-outs of the original damper drives that are used for by-pass after the "ozone season".

Reheat panels (all 6 units) along with new reheater outlet headers at 5 units are being installed. The headers are not failing, but are replaced to facilitate the panel interface welding.

Stainless steel overlays have been made on the water walls in the primary furnace over the past several years. Plant personnel believe this has reduced forced outages on the boiler.

FD Fan variable frequency drives, (new) Units 1, 2, 3, 5, & 6, Sept 2002 to Nov 2003.
ID Fan variable frequency drive, (new) Units 1-6, Sept 2002 to Nov 2003.
Boiler digital control system upgrade, Units 1-6 Sept 2002 to Nov 2003
Boiler Efficiency Test, performed periodically

3.3.2.2 Turbine

Overheating occurred in the Unit 3 T-G in 2003. Root cause was new instrumentation that failed. Extensive inspections performed, and no significant damage to the generator was found.

As noted above, the H.P. turbine components are on a 10 year major overhaul schedule and the L.P. sections on a 20 year major overhaul schedule. Examinations are made annually during the boiler shutdowns. No unusual problems reported since 2002.

A spare HP and LP rotor exists on site for the GE turbine generators. The General Electric spare rotors are maintained and stored at Clifty Creek since they have six GE units.

Turbine Supervisory Controls upgrade, Units 2 & 5, 2005
Generator Seal Oil Flow Test, Unit 4 Oct 2003
Turbine Steam Seal Flow Test, Unit 4, April 2004
Emergency Governor Test, Unit 4, (Turbine Overspeed) April 2004
Turbine Emergency Bearing Oil Pump Test, Unit 4 January 2005
Turbine Heat Rate Test, Unit 4, March 2003
H.P. Generator Inspected, Unit 1, May 2003
H.P. Generator Inspected, Unit 2, Feb. 2003, rewind recommended by 2007

H.P. Generator Inspected Unit 3, June 2003, rewind at next inspection in 2006
H.P. Generator Rotor inspected, Unit 5, Jan 2004, passed hi-pot test
L.P. Generator inspected 2003, Unit 1, next inspection 2013
L.P. Generator inspected Feb 2003, unit 2, next inspection 2005, rewind recommended 2010 or 2011
L.P. Generator inspected June 2003 after overheating, Unit 3 Rewind recommended in 2006
L.P. Generator inspected Jan 2004, Unit 5, passed hi-pot test. Next inspection 2008

3.3.2.3 Emissions Control System

Selective Catalytic Reduction (SCR) systems were installed on 5 of the 6 boilers at Clifty in 2002 and 2003. Since the current NOx regulation allow "bubbling" of the emissions from both Clifty and Kyger and since OVEC chose to design the reactors for a NOx removal efficiency of 90%, sufficient margin existed to allow one unit to remain uncontrolled. SCR operation is required only during the "ozone season". It is anticipated that year round SCR operation will be required by January 2009. These systems are capable of continuous operation and this mode of operation would result only in the additional variable operating costs associated with increased consumption of ammonia and catalyst. All associated SCR equipment maintenance would increase proportionally to SCR operating hours.

Electrostatic Precipitators (ESP) were installed on all 6 Clifty units in the late 1970's. Units 1-5 were fitted with "cold side" ESP's while unit 6 was fitted with a "hot side" ESP. The difference in these systems is the location of the ESP relative to the air preheater. The "hot side" are located upstream while the "cold side" ESP is located downstream. The Unit 6 ESP was the first installed at either plant and "cold side" ESP equipment was chosen for the remaining units. The ESP systems were originally designed for operation with eastern bituminous coals or western sub-bituminous coals. Particulate control on all 11 units has consistently operated well below the regulatory limits.

Flue Gas Desulfurization units (FGD) are not currently installed at Clifty. OVEC plans to install FGDs on all 6 units by January 1, 2010. Conceptual design is underway and detailed design will begin shortly. A new stack may be required as part of the FGD retrofit. The plant is currently burning between 60% and 80% PRB fuel in an effort to reduce SO2 emissions. Future SO2 emissions will be managed with the purchase of SO2 credits until the FGD systems are operational.

No mercury reduction systems are currently installed on any of the Clifty units, although preliminary plans are being considered for likely mercury reduction requirements.

During each available opportunity, forced or planned outage, the SCR is inspected for fly ash accumulation and cleaned if needed.

CEMS and other monitoring systems are calibrated and maintained as necessary.

3.3.2.4 Stack

Each stack was inspected within the last 2 years and each underwent expensive repairs totaling over $800,000 for both. With the recent repairs both stacks should be in very good condition. The existing stacks are expected to be replaced with the installation of the planned FGD systems in 2009.

3.3.2.5 Balance of Plant

All steel, concrete foundations, turbine generator pedestal and other structural components appear to be in good condition. When the SCRs were installed, columns in the T-G building were reinforced to support the increased loads.

Intake and outflow structures are periodically inspected and no significant deterioration. Zebra mussels have been an occasional problem to clean out, but they have not caused any de-rating or forced outages in the last 3 years.

Critical pipe and pipe supports are inspected annually and adjusted as needed.

Electrical cable deterioration has not been a problem.

Instrumentation and controls are continually being maintained and upgraded. The major upgrade in the control rooms to the Ovation system has been accepted by plant operators and the system is working properly.

Condensate controls upgrade, Units 1 – 5, Sept 2002 to May 2003
Ammonia on demand system (new), Units 1-5, April 2003
Boiler Feed Pump Test, performed periodically
North IP Feedwater Heater retubed, Unit 5, November 2004

3.3.2.6 Coal Supply

In July 2005 BNSF-UP joint line maintenance activities were limiting Powder River Basin (PRB) coal deliveries. This was expected to be a temporary hindrance, but PRB coal on hand is very low. The plan is to burn 60% PRB and 40% eastern coal until the coal storage reaches a level closer to the desired 40 days.

3.3.2.7 Transportation

Coal is delivered to plant by barge. No recent changes have been made to the dock, unloading facility or coal pile transfer conveyors.

3.3.2.8 Electricity Transmission

No recent changes have been made to the electrical transmission system. The transmission is the responsibility of OVEC, and no long term problems have been identified. Spare transformers at the generator output are available in case of failure.

4.0 ENVIRONMENTAL COMPLIANCE

4.1 COMPLIANCE WITH CURRENT REGULATIONS

No emission test results have been performed since June and July 2002, as reported in the 2004 report. The particulate emission regulation is 0.10 lb/mmBTU. The maximum particulate level emitted in 2002 was .045 lb/mmBTU on Unit 1, with a low of 0.015 lb/mmBTU on Unit 3. These tests will be repeated in 2005.

NOx controls were installed in 2002 and 2003 as SCRs were installed on each of the 5 boilers at Kyger and 5 of the 6 boilers at Clifty. Upgrades to the existing ID fans were required to ensure that maximum unit output would not be compromised. All SCRs were designed for 90% removal efficiency and continue to operate at or near design.

The only significant operational issue with the SCRs to date is the accumulation of fly ash primarily on the first layer of catalyst. On several occasions a unit de-rate resulted at Clifty due to excessive pressure drop across the reactor and insufficient ID fan capacity. Clifty is working to develop a process for re-entraining fly ash that has accumulated on ductwork turning devices or the first layer of catalyst. The Kyger plant has seen some fly ash accumulation but has not had to take de-rate production. Based on industry experience, it is not uncommon that fly ash accumulation increases as the percent of PRB increases to 80% PRB fly ash has been a problem at most facilities operating with high percents of PRB and SCRs. This possibility of increased accumulation is included in the financial forecast.

Due to safety concerns associated with anhydrous and aqueous ammonia the decision was made to install ammonia on demand (AOD) systems. AOD is a fairly complex system that takes urea pellets, dissolves them in water and converts the liquid to ammonia. The capital and operating cost is greater than the more conventional systems but health risks associated with an accidental release are far less. The system has operated very reliably and has required only moderate maintenance. Some OEM provided valves resulted in less than adequate reliability and were replaced with high quality units.

In the late 1970's Electrostatic Precipitators (ESP) were installed on each of the boilers at Clifty and Kyger. Also during this retrofit new steel reinforced concrete stacks with metal liners were constructed and the existing stacks were partially demolished. As a part of the ESP retrofit each boiler was converted to balanced draft and new induced draft fans were installed. ESP performance and reliability has been very good. Actual particulate emissions are consistently below regulatory limits. Continued excellent performance from these systems is expected. No significant issues exist.

No significant pollution releases have been reported by OVEC, although load has been reduced on occasion to reduce opacity and NOx emissions. Both facilities continue to operate and comply with all federal and state environmental regulations. Environmental performance and management continues to be good.

4.2 MODIFICATIONS REQUIRED FOR SCHEDULED REGULATIONS

A review of environmental compliance at both Clifty and Kyger suggests that both facilities have done a good job in meeting or exceeding state and federal regulations for air, water and solid waste pollution management. The proposed installation of FGDs on each operating boiler will result in over compliance and the accumulation of SO2 credits.

Wet Flue Gas Desulphurization (FGD) systems are currently planned for each of the 11 boilers. The current schedule has the first systems operational at Kyger in mid- 2009, with all remaining systems operational by January 2010. Detailed design is currently underway for the Kyger plant with conceptual engineering ongoing for the Clifty site. ID fan modifications or booster fans will be required to implement this change.

At this time mercury control appears to be the only upcoming regulation that posses a sizable risk to the operation of the facilities. OVEC is estimating 35% - 40% mercury removal from the co-benefit of the SCR and FGD. This estimate is based on tests performed at Clifty Plant that have shown oxidation of mercury through the SCR was higher than what most other units burning PRB have experienced. It is possible that the chlorides in the eastern coal have contributed to these better than average oxidation results. OVEC is actively involved with the states of Indiana and Ohio with respect to the structuring of the final implementation plan for mercury. Current discussions with Indiana and Ohio indicate that units burning PRB will receive larger allocations than plants burning Eastern coal only. The allocations for Clifty and Kyger are expected to be bubbled and "cap and trade" arrangements will be available. Based on all this information, OVEC believes it will meet Phase 1 mercury control requirements with the use of the SCR and FGD equipment. This is a realistic position but some risk does exist. Industry studies are still ongoing to determine the true effectiveness of SCR and FGD on mercury control, especially when firing sub-bituminous coals. Depending on the actual effectiveness and the ultimate reduction requirements, additional controls might need to be installed on some or all of the units. At this time OVEC believes that activated carbon might be one method to achieve Phase 2 requirements.

5.0 REVIEW OF OPERATIONS PLANS

5.1 COAL SUPPLY

In 2006, the Kyger plant plans to burn 80% Powder River Basin coal, and 20% Eastern mid-to-high sulfur coals from various locations. This requires changes to the coal yard to allow mixing of the coal as it is offloaded from the barges. Kyger is planning to add six barge cells upstream of the unloading dock to accommodate the additional barge traffic with the PRB coal, and to purchase 135 new coal cars for transporting western coal to the Mississippi River barges. These changes will be made before June 2006.

Deliveries of PRB has been low and is expected to remain low into November. The primary cause is rail bed wash outs on the Union Pacific (UP) line in Wyoming. UP has invoked the Force Majeure clause in its contract. PRB is transported by rail to the Mississippi River near St. Louis and then barged to the plant.

It is possible for Clifty to operate similarly to Kyger on a lower than 60% PRB coal. The fly ash cannot be sold at less than 60% PRB for concrete filler, and thus the fly ash landfill will fill faster. To date, OVEC does not plan on having to start burning the lower percentage of PRB.

AEP provides coal supply coordination to OVEC. AEP is working the PRB delivery problem, but there are not many options with the coal trains.

5.2 EQUIPMENT UPGRADES

The following equipment upgrades are planned over the next few years. This is in addition to standard inspection and maintenance programs that are in place.

Kyger and Clifty plants plan to replace the six 25,000 gallon fuel oil underground storage tanks with new above ground storage tanks in 2005 and 2006. The existing underground tanks will be cleaned and left in place. OVEC is currently awaiting regulatory approval for their plan.

At Kyger, all of the seam welded Hot Reheat fittings are planned to be replaced, except for the fabricated WYE fitting. This will eliminate virtually all of the pipe that could cause a catastrophic rupture.

Many of the turbine – generators have never been rewound. These are currently planned and budgeted through the year 2013.

The plant controls Ovation network will continually be upgraded in the coming years.

Testing on Kyger Unit 5 stator will be used to indicate probable condition of other unit stators.

Kyger Unit 5 intercept valve stud holes to be repaired in 2006.
Clifty Unit 6, Condensate Controls Upgrade, October 2005

Clifty Units 1, 3, 4 & 6, Turbine Supervisory Controls Upgrade, October 2005 to 2007

Clifty Units Reverse osmosis (new –additional 200gpm), spring 2006

Clifty 6, South IP Feedwater Heater Replacement, October 2005

Clifty 5, Main Steam pipe has serious sag. Planning to replace a section of the pipe and review pipe support designs.

At Clifty, Retubing of HP heaters continue with 47W and 47E in Sept 2005 and 26W later.

Combustion optimization software being considered.

Spare transformer for ID fan adjustable drives being recommended by AEP. Robicon will probably not have a transformer available if failure occurs. FGD study may effect this recommendation.

5.3 ENVIRONMENTAL PLANS AND UPGRADES

At Kyger, a recent survey indicated that the existing South Fly Ash Pond has enough capacity to accept all fly ash generated at the plant for the next five to ten years. Kyger sells approximately 70% of it boiler slag for beneficial reuse, and as a result, the capacity of the South Boiler Slag Pond is much greater than the Fly Ash Pond.

FGD scrubbers are expected to be designed and installed on all units by January 1, 2010 to meet SO2 regulatory requirements.

At Kyger, a new landfill that would be capable of accepting fly ash, boiler slag and FGD byproduct is being planned as part of the FGD upgrade. The first phase of this landfill would have a designed capacity of approximately 15 years for these materials. OVEC has options on the land adjacent to the plant that OVEC is considering purchasing.

At both plants, extensive ducting and a new stack will need to be installed for the scrubbers.

At Clifty, the bottom ash pond will be modified or closed to provide space for the scrubbers.

At both plants, modifications will need to be made to the ID fans, probably adding a booster fan at each unit.

OVEC worked with the State of Ohio in the 1970's, conducting tests at both plants that ultimately resulted in the variance of Clifty and Kyger from 316a requirements. Every 5 years during the renewal of their NPDES permit, OVEC requests a continuation of the variance and have always been granted it. OVEC expects this process to continue.

At both Clifty and Kyger plants, the plants' circulating water flow is under a specified percentage of the Ohio River flow rate. This allows both plants to be exempt from the

Entrainment Section of the 316b regulations. OVEC continues to monitor regulatory actions that could change this exemption. Currently OVEC believes the most extensive modification that might be required under the Impingement Section of 316b is modification of the traveling screens. Another alternative that has been proposed is to restock the river with fish. Given the existing permits, OVEC does not consider it possible that major changes will be required to intake or outflow structures.

5.4 TRANSMISSION ADEQUACY

No significant changes are planned.

5.5 PLANNED O&M EXPENDITURES

OVEC is budgeting approximately $75 million dollars per year for Operations and Maintenance through 2008. Much of this cost is fixed by the labor and benefits associated with the nearly 700 people on payroll. Comments regarding these projected expenditures are presented in Section 7.0. In 2009, this projected general cost level is augmented by $6 million, for operation of the scrubbers at one plant for half the year, and an additional $4 million for anticipated expanded operation of the SCRs at both plants from five to 12 months per year. Starting in 2010, a scrubber O&M cost of $24 million is added. The $4 million per year increased SCR costs are retained. The total projected demand costs, of which the O&M costs are a dominant component, are escalated after 2010 by 2.5% per year.

5.6 PLANNED CAPITAL IMPROVEMENTS

Per the budget documents, OVEC is planning to spend $80 million to upgrade the Kyger coal yard to accept and blend a higher percentage of PRB coal.

An additional $665 million is budgeted to install the scrubbers at all 11 units, including the changes to the ID fans, ash ponds and stacks.

OVEC is budgeting $20 million per year to upgrade miscellaneous equipment, escalated by 2.5% per year. In addition, $6 million to $7 million is added in 2012 and selected later years for SCR catalyst replacement when the SCRs operate 12 months per year starting in 2009.

6.0 PROJECTED LIFE EXPECTANCY

The focus of this study is on the physical and operational life expectancy issues; namely assessments of projected plant and equipment longevity and performance based on operating history and experience, current material condition assessments, and plant owner plans for operating and maintaining the subject facilities. This independent engineering study addresses only issues of projected plant performance and the reasonableness of costs projected by owners to maintain desired levels of plant performance. This study does not address issues of economic and financial life expectancy except to point out where existing cost projections appear to be optimistic (low) and where there appears to be a significant likelihood of the plants experiencing higher than budgeted costs that could erode revenue margins. This study focuses on assessing the technology, material condition, operations history, and plans for future operation of Kyger Creek and Clifty Creek, and making judgments about physical and operational life expectancy.

The following conclusions emerge from this review:

1. The five Kyger units and six Clifty units have been operated within design parameters and maintained at a high level for 50 years. The plants continue to generate reliably at or near their rated capacity. Actual steam temperatures are less than design, which provides extra design margin for the boiler headers, piping and turbine components.

2. Fuels are being purchased to optimize SO2 emissions strategy until such time as FGD systems are installed. These scrubbers are planned to be operational for all units in both plants by January, 2010. URS has not reviewed the coal procurement strategy, the flexibility of coal usage as time goes on, or the design optimization of the planned FGD systems.

3. The units are all being operated as base load units with very few periods of cycling. If the units were changed to load following or cycling operation, it is expected that life expectancy would be adversely affected by adding significant thermal cycles to equipment, and by operating equipment at less than optimum conditions. OVEC has no plans to convert to cycling.

4. Maintenance in 2003 through 2005 has continued on the expected schedule described in the 2004 report. Inspection and maintenance expenditures indicate a continued commitment by OVEC to continually maintain the plants for full operation over at least the next 20 years. Should maintenance and inspection levels be reduced, life expectancy and availability would be expected to be adversely affected.

5. Note that serious operations errors, maintenance errors or equipment failures that can cause explosions, fires, or other catastrophic failures are always a possibility in power plants. In these evaluations, it is assumed that continued good operations and maintenance practices ensure that no such serious event occurs.

6. If the units continue to be operated and maintained as they are currently, and have been for the past several years, and if current plans for equipment maintenance and upgrades

are successfully conducted on an ongoing basis, then an additional 20 years or more of useful life can be reasonably expected.

7.0 REVIEW OF SYSTEM BUDGET AND FINANCIAL PROJECTIONS

This section presents commentary primarily on the budget projections presented by OVEC and IKEC in the spreadsheets of References 1 and 2. The budget projections are limited to one scenario, the owners' base or reference case. No projections based on alternative scenarios, most particularly scenarios addressing "stress" or higher risk circumstances, have been presented to URS.

OVEC has informed URS that the dollar figures in Reference 1 are in nominal dollars. For example, expenditures listed for the year 2010 are in 2010 dollars. Those listed for 2015 are in 2015 dollars. It is assumed that all budget data presented to URS are in nominal dollars.

The following observations and judgments are offered.

1. Capacity factors are projected to be in the 75 to 80% range for the remainder of plant life. This appears to be reasonably consistent with recent operating experience, taking into account energy sold to shareholder companies. A 2% reduction in generation capacity is assumed for auxiliary power when the scrubbers are added in 2010.

2. Based on 100% funding by the bonds described in Reference 1, the projected scrubber capital cost for Kyger is about $301 per kilowatt, presumably in roughly 2009 dollars. The corresponding figure for the Clifty scrubbers is $276 per kilowatt. The description of the planned FGD systems elsewhere in this report indicates that each generating unit at each of the plants will have its own scrubber. URS assumes that this is the result of separate scrubber optimization studies performed by or for the owners. Each scrubber is therefore intended to serve a generating unit of slightly over 200 megawatts. Reference 3 presents capital cost estimates for scrubbers for plants of varying sizes, the smallest of which is 300 megawatts. The capital cost of a scrubber for a 300 megawatt plant, when escalated to 2009 dollars, appears to be about $318 per kilowatt. This appears to be reasonably in keeping with the Kyger and Clifty estimates, which are 5% to 15% lower. Cost estimates made in preliminary design phases are sometimes exceeded in actual construction.

3. General capital improvements are budgeted at a nominal $20mm per year with a 2.5% annual escalation on an ongoing basis, augmented periodically after 2009 to cover the cost of SCR catalyst replacement, reflecting the twelve month operation of the SCRs. This appears reasonable, since increasingly older equipment is likely to require more replacement expense as time goes on, and inflation will make such replacements more costly in terms of nominal dollars.

4. No further comments are offered with regard to the capital improvements items in Reference 1. Consideration of bonds or other financial instruments is outside the scope of this study.

5. Projected demand costs, which are made up primarily of operation and maintenance costs and general and administrative costs, are escalated long term at about 2.5% per year. This

seems appropriate in light of general inflation expectations in the 2.5% per year range (Reference 6), and increasing maintenance requirements as the plants continue to age. There may be potential offsetting economies in the future, perhaps having to do with the commonality of the units at both plants and possible work force efficiencies. This study has not reviewed balancing potential cost increases and future efficiencies.

6. The capital costs of periodic SCR catalyst replacements are reflected in the cost projections. The SCR operations and maintenance costs are increased starting in 2009 to reflect twelve months of SCR operation rather than the five months of operation prior to 2009.

7. It is assumed that the costs of rewinding the generators have been appropriately included in the operation and maintenance cost projections. These costs should end by 2014, when the rewindings are scheduled to be completed. This may leave some margin for increases in operations and maintenance costs elsewhere.

8. It is expected that operations and maintenance costs associated with the scrubbers, starting in 2009, would result in a major increase in this category of costs. The Reference 1 cost projections include $6mm in 2009 for a half year of operation of the scrubbers at one of the two plants. Starting in 2010, scrubber operation and maintenance costs are budgeted at $24mm per year and escalated in later years. This appears to be of the appropriate magnitude. The actual O&M costs will be dependent on the actual installed equipment, and can vary greatly. For illustrative purposes, with the operations and maintenance cost ranges given in Reference 4 as guidance, assume a fixed O&M cost of $10 per kilowatt year and a variable O&M cost of about $1.3 per megawatt hour. These assumptions lead to both fixed and variable operations and maintenance costs on the order of $20mm per year, or $40mm per year in total, for both plants combined. Since OVEC recognizes this issue, OVEC needs to purchase equipment to minimize O&M costs without significantly increasing the budgeted capital costs.

9. Projected energy costs escalate at an average of 2.0% per year over the long term. These costs are driven primarily by the cost of coal. Projected coal costs and mixes presented to URS are based on existing contracts that extend to 2009. After that, reliance on new contracts or the spot markets for coal will be required. Long term coal price escalation rates derived from projections in the EIA Annual Energy Outlook 2005, Reference 7, suggest a long-term escalation rate in the range of 2.0-2.5% per year. This is not dramatically higher than current owner assumptions, and should not create concerns about operational lifetime. Higher than projected escalation of coal costs would likely affect all coal fired generators, and the relative market positions of Kyger and Clifty would probably not be seriously affected.

10. The spreadsheet addressing SO2 allowances shows an allowance price of $850 per ton each year from 2005 through 2009. This seems consistent with price projections in Reference 5.

8.0 CONCLUSIONS

8.1 ABILITY OF PLANT TO OPERATE AS PLANNED

Both the Kyger Creek and Clifty Creek plants are operating at or near their design capability with about 90% and 84% availability. In recent years the forced outage rate has been 3.8% to 4.8% at Kyger and 7.4% to 8.5% at Clifty Creek. The national average for coal fired plants of this size was 87.5% Availability Factor and 4.44% Forced Outage Rate from 1999 to 2003. The entire OVEC system is operating very close to the national averages.

Each unit has been base loaded and the 11 units as a system have produced a low of 14.49 GWhours in 2003 and a high of 16.39 GWhours in 2004. The 2005 production is 8.3 GWhours which will exceed the 2004 production if the trend continues. This is encouraging in that the addition of the SCRs has not reduced the net generation output or capacity of the system.

There is some concern that when PRB blend is greater than 60% at Clifty Creek, all seven pulverizers must be operational to achieve full load. As 80% PRB blend is re-instituted at Clifty Creek and instituted at Kyger Creek, there could be a possibility that there will be more de-rated operation while pulverizers are maintained. OVEC plans to avoid this de-rating issue by burning less PRB temporarily, and by planning the pulverizer maintenance during annual outages, as much as possible.

The short term budget projections are based on 15.6 to 15.8 GWhours per year, with some variation for planned outages. From 2010 on, the budget projections are based on 15.2 GWhours per year, assuming auxiliary generation demand of 2% for the FGD scrubbers. The OVEC system appears capable of producing power at this level as long as forced and planned outages can be kept at the current levels.

8.2 ADEQUACY OF PROJECTED CAPITAL AND OPERATING COSTS

To summarize the comments in Section 7.0, long term projections of generation output, operations and maintenance costs, fuel costs, and capital equipment costs are reasonable. No alternative case projections have been presented to URS. The budget projections appear capable of supporting this continued operation.

8.3 ENVIRONMENTAL COMPLIANCE, PRESENT AND FUTURE

A review of environmental compliance at both Clifty and Kyger suggests that both facilities have done a good job in meeting or exceeding state and federal regulations for air, water and solid waste pollution management. The current plan appears to be adequate to meet proposed changes in the regulations but some risks do exist.

In the late 1970's Electrostatic Precipitators (ESP) were installed on each of the boilers at Clifty and Kyger. Also during this retrofit new steel reinforced concrete stacks with metal liners were constructed and the existing stacks were partially demolished. ESP performance and reliability has been very good. Actual particulate emissions are consistently below regulatory limits. Continued excellent performance from these systems is expected. No significant issues exist.

With the installation of ten SCR systems in 2002 and 2003, OVEC is meeting or exceeding NOx emission requirements at both facilities. Over compliance has resulted in the accumulation of NOx credits. SCR performance has been very good and similar performance is expected in the future. The only significant operational issue with the SCR systems to date is the accumulation of fly ash primarily on the first layer of catalyst. The ash accumulation is no worse than other US electric generating plants burning PRB coal. OVEC is working appropriately to manage the accumulation and it is not expected to significantly effect system operation.

Wet Flue Gas Desulphurization systems are currently planned for each of the 11 boilers. The current schedule has the first systems operational at Kyger in mid- 2009, with all remaining systems operational by January 2010. Detailed design is currently underway for the Kyger plant with conceptual engineering ongoing at the Clifty site. FGD technology is very mature; therefore the risk of these systems not meeting performance guarantees is very low. O&M and auxiliary power costs should also be very predictable. The proposed installation of FGD systems on each operating boiler will result in over compliance and the accumulation of SO2 credits.

At this time mercury control appears to be the only upcoming regulation that posses a sizable risk to the operation of the facilities. It should be noted that OVEC's current position is that mercury control for Phase 1 will be achieved through the SCR and FGD. Testing at Clifty Plant has indicated that mercury oxidation rates are higher with their PRB-bituminous coal blend than other PRB facilities have reported. OVEC is expecting 35-40% mercury removal from the co-benefit of the SCR and FGD systems. OVEC believes that activated carbon or some other technology will be added to meet Phase 2 requirements.

Both plants have maintained an excellent record with respect to wastewater discharge. Good compliance is expected to continue in the future. In the 1970's OVEC conducted extensive testing that resulted in both the Clifty and Kyger Plants receiving a variance from 316a. Also, 316b does not apply at either facility due to the relatively low circulating water flow rates compared to the average flow rate of the Ohio River. OVEC feels confident that both the 316a variance and 316b exemption will continue.

Management and compliance with the solid/hazardous waste regulations has been good at both plants. Each facility has worked very hard to minimize the use of materials and chemicals that result in the disposal of a hazardous waste. Programs are in place to replace hazardous waste with non-hazardous alternatives, and where hazardous materials must be used, to minimize the resulting waste.

At Kyger and Clifty, 6 underground fuel oil storage tanks will be closed out at each plant and above ground tanks will be installed. If leaks are detected then it is quite possible that ground water monitoring wells will have to be installed around the tanks requiring the plant to monitor ground water for contamination. Monitoring will likely continue as long as the plant is operational. Some risk exists with the closure of these tanks associated with possible ground water contamination and the resulting remediation requirements.

8.4 COMPLIANCE WITH GOOD ENGINEERING PRACTICES

OVEC compiles a number of matrices based on production, forced outages, repairs, emissions, cost of production, energy / kWh and others. It is clear from talking to the plant personnel that this data is used in its planning and decision making to focus resources on operations, inspection and repairs.

Interactions between plant systems are considered when making major decisions, such as additional pollution control equipment, changes in coal blending and water chemistry. This management approach helps avoid modifications that will benefit one portion of the process while not necessarily improving the availability and generation of the entire system.

Consultants are used as appropriate to develop recommendations.

Eleven units have operated for 50 years with minimal major incidents. This implies that the base equipment is operable without causing major incidents, and that the processes and procedures are well enough understood that major mistakes have not been made.

Each forced outage is analyzed for trends that indicate a systemic problem. When such problems are discovered, resources are available and are assigned to develop a long term solution.

The OVEC system has a great advantage over many other utilities in that the plants are virtually the same age, with the same equipment, and very similar operating history. Once a systemic problem is observed at one unit, evidence of similar issues can be examined at the other ten units. This limits the "surprises" that can occur at utilities with several different types of equipment, fuel, and operating philosophies.

8.5 EXPECTED LIFE OF PHYSICAL ASSETS

Projecting the life of any equipment, particularly equipment 50 years old is not an exact science. It is obvious that equipment will wear out and must be repaired or replaced. Boiler tubes, rotating equipment blades and rotors, high temperature pipe, heater tubes, pulverizers and other plant equipment are continuous maintenance items. Judgment criteria to evaluate expected life and URS's judgments are as follows:

1. **Is there evidence of degradation that indicates expended life of major equipment?** The annual planned inspection programs of boilers and high energy equipment, and the attention to detail on maintaining supports that could increase stresses means that none of the boiler headers, steam drums, and most piping systems are not in need of major repair or replacement. Rotating equipment has been operating at high levels of performance without any apparent degradation.

2. **Is there a plan based on past experience and reasonable engineering judgment to identify failing equipment before it becomes a forced outage?** OVEC continues to maintain spare turbine rotors and main transformers. There is redundancy in the

boiler feed pumps and condensate pumps. Inspections are routinely performed on a high percentage of the major equipment. Plants are heavily staffed with experienced personnel in maintenance, operations and management. This provides a substantial "corporate memory" that helps identify root causes when incidents occur. This corporate mentality could blind personnel from new ideas, but it appears that OVEC consults often with AEP and other consultants to avoid this trap.

3. **Are there reasonable contingency plans for repair of equipment?** Equipment repairs are planned up to five years in advance. Generator re-winds are planned out through 2013. The maintenance and capital expenditure budgets are consistent on an annual basis. This implies a corporate mentality to continue to maintain and inspect equipment on a continual timetable, and not to try to manipulate the budget for low spending for a year or two, resulting in much higher costs 3 or more years later.

4. **Is it reasonable to assume that the equipment will be operated within design parameters?** The experience shows that the equipment is not degrading at a high rate. Primary steam output is at less than design on pressure and temperature. Given the 1050^0F design temperature, operation at 10^0 to 30^0 F less than design provides significant increases in stress allowable on the high temperature headers, tubes and pipe.

5. **Are reasonable safeguards in place to avoid major operational incidents that could cause catastrophic damage?** URS did not review operations procedures. However, the recent history shows no significant operational errors that resulted in a major forced outage. Three (3) forced outages were shown on the OVEC data as "Personnel Error" since 2002. This low level may be skewed a little since often there are multiple causes of a particular outage and it is often easier to blame equipment. However, there are no apparent major incidents of water hammer, turbine overspeed, dead headed pumps, loss of drum water level or other events that are usually associated with operator error.

Based on the current condition of the plants, the plans for continued inspection and maintenance, the continued good operational record, and the plant resources to implement these plans, URS believes it is reasonable to expect that the Kyger Creek and Clifty Creek plants will be able to physically operate for the next twenty years or even longer.

8.6 MAJOR RISKS TO LIFE EXPECTANCY

The above conclusions are based on materials presented by the owners and assumptions about both existing conditions and future operations. As noted earlier, the operating and budget projections are limited to one scenario, the owners' base or reference case. No projections based on alternative scenarios, most particularly scenarios addressing "stress" or higher risk circumstances, have been presented to URS. Ultimately, physical life expectancy is determined by cost considerations, generally fairly sudden and unacceptably large cost increases rather than long-term gradual erosion of revenue margins. The following are viewed as the major items that could cause a significant change in costs with resultant decrease in physical life expectancy. Some comments also touch on economic life expectancy.

1. Equipment failures and/or performance significantly below current expectations that are based on material condition assessments and equipment lifetime prognosis. Key items of equipment that could be subject to unexpected major failures include boilers, steam turbines, generators, transformers, etc. Plant performance parameters that are subject to technical risks include heat rate, summer and winter megawatt ratings, forced outage rates particularly if these are high enough to adversely affect plant capacity value and capacity market revenues, and ability to provide ancillary services and secure their attendant revenues. There are really two categories of risk here; catastrophic mechanical failures, which may be a serious issue for plants and equipment of this vintage, and failure to perform as designed. The latter could apply to individual units on an overall basis, or to specific subsystems, original or new.

2. Units are currently not intended to be operated other than base loaded. Additional damage would be incurred by cyclic or load following operation. Thermal stresses and risk of operational events during changing loads and startups would be increased. During power cutbacks or shutdowns, there is risk of damage caused by condensing steam; undrainable low points, entrapped coal or ash, and equipment failures during re-start. Cycling operation that is forced by changes in power market conditions could significantly shorten operational life expectancy. OVEC has no plans to modify their base loaded operation of these units.

3. A serious operational error that creates considerable direct and collateral damage. Extended downtime would increase cost and reduce production. Damaged equipment may not be replaceable, or may be inordinately expensive to replace.

4. Extended loss of reliable PRB coal appears to be a substantial risk to plant availability until the coal pile is increased to several weeks of supply, or until environmental controls additions would allow increased use of local coal. While eastern coal could probably be substituted, loss of fly ash sales, and increases in purchasing SO2 allowances could be substantial.

5. Major regulatory changes in mercury emissions limits or other pollutant emissions would cause an increase in required equipment and likely erosions of plant capability and performance.

6. A major fire or other such incident caused by relatively minor failures such as the lube oil system have been known to shut down plants for a long period of time.

7. Major new environmental or other regulatory requirements that selectively impact on Kyger Creek and Clifty Creek to a greater extent than they impact on newer coal plants in the population. An example that comes to mind is an enhanced "new source review" legislation that makes it prohibitively expensive for Kyger and Clifty to continue with major plant improvements.

Most if not all of these risks are generally applicable to all coal fired plants in the United States. Such items as regulatory changes would presumably apply not only to Kyger and Clifty, but also to all other coal fired plants.

A different type of risk could be a combination of a major shift in fuel prices (e. g. coal vs. gas), early wide deployment of new technologies such as IGCC, and onerous new environmental regulations that would cause a shift from coal as a low cost producer to other energy sources, and particularly impact on older coal plants perhaps having high heat rates. Combinations of such circumstances could produce a radical change in the Kyger and Clifty positions in the power markets and tend to shorten economic life. However, such combinations of circumstances are not currently anticipated over the next twenty year horizon.

This information is redacted and provided under seal pursuant to a Petition for Confidential Protection.

Pages 1 - 8

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 3

Witness: Lonnie E. Bellar

Q-3. Explain whether situations arise in which surplus power exists from the OVEC generation resulting in power being sold into the wholesale market. If applicable, include whether the OVEC ICPA participating companies share in off-system revenues generated, and how the revenues are shared.

A-3. OVEC is not a participant in the wholesale power market. The OVEC ICPA participating companies receive their allocation of the generation in accordance with their ownership share of OVEC. The Companies use their share of OVEC generation to serve their native load customers.

CONFIDENTIAL INFORMATION REDACTED

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 4

Witness: Charles R. Schram

Q-4. The LG&E/KU applications contain several references to OVEC's "relative" low-cost generation. Identify the entities and costs to which the term "relative" refers. Include any comparisons necessary to substantiate the "low-cost" reference.

A-4. The reference to OVEC's relative low-cost generation is a comparison of the variable cost of OVEC energy to coal-fired units in the jointly dispatched LG&E/KU system. During 2010, OVEC's average variable cost was $[redacted]/MWh while coal units in the LG&E/KU system ranged from $[redacted]/MWh to $[redacted]/MWh.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 5

Witness: Charles R. Schram

Q-5. From a cost perspective, describe how OVEC power purchases compare with power generated by LG&E/KU as a combined system, including both coal-fired and gas-fired LG&E/KU generating units. Include in the description the stacking order of the KU/LG&E system and where the OVEC power would rank in the stacking order.

A-5. OVEC's 2010 average variable cost of $[redacted]/MWh compares favorably to the LG&E/KU system average cost. The LG&E/KU system's 2010 average variable cost for energy produced by coal and gas units was $[redacted]/MWh. (This excludes test energy produced by Trimble County 2, which was not in commercial status during 2010). All power received from OVEC is considered an economic resource and is allocated to the Companies' native load customers. The information on the following page shows that OVEC's average variable cost does indeed compare favorably to the total variable production costs of the Companies' coal units and to the fuel costs for the Companies' gas units.

Coal Units	Total Variable Production Costs ($/MWh)
Mill Creek 3	[redacted]
Mill Creek 4	[redacted]
Mill Creek 2	[redacted]
Mill Creek 1	[redacted]
Ghent 2	[redacted]
Ghent 1	[redacted]
Ghent 3	[redacted]
Trimble County 1	[redacted]
Cane Run 5	[redacted]
Ghent 4	[redacted]
Cane Run 4	[redacted]
Cane Run 6	[redacted]
Green River 4	[redacted]
Brown 2	[redacted]
Brown 3	[redacted]
Brown 1	[redacted]
Green River 3	[redacted]
Tyrone 3	[redacted]

Gas Units	Fuel Costs ($/MWh)
Trimble County 6	[redacted]
Trimble County 5	[redacted]
Trimble County 10	[redacted]
Trimble County 8	[redacted]
Trimble County 9	[redacted]
Brown 6	[redacted]
Brown 7	[redacted]
Trimble County 7	[redacted]
Brown 5	[redacted]
Brown 11	[redacted]
Paddys Run 13	[redacted]
Brown 9	[redacted]
Brown 8	[redacted]
Brown 10	[redacted]

Source: Utility Financial Reports

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 6

Witness: Charles R. Schram

Q-6. Explain whether there are circumstances in which LG&E/KU would consider purchases made from OVEC under the existing or proposed contract as economy power purchases.

A-6. All of the energy purchased from OVEC is considered a long-term economic resource and allocated to native load.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 7

Witness: Lonnie E. Bellar

Q-7. Identify by name each generating unit owned or operated by OVEC. For each generating unit, provide the following information: date constructed; type of fuel burned and sulfur content of fuel; heat rate; nameplate generating capacity; net demonstrated summer and winter generating capacity; description of existing environmental controls and date each was installed; location and type of landfill; and a description of cooling towers and date installed.

A-7. OVEC owns two generating stations, Clifty Creek and Kyger. Please see the attached tables for all of the requested unit-specific information except the following:

Location and type of landfill(s)

Kyger recently completed Area 1, Part 1 of the Type III Residual Waste Landfill. The first partial phase of the existing Type III Restricted Waste Landfill at Clifty has been upgraded to a Type I Restricted Waste Landfill. Both landfills are now permitted to accept all coal combustion byproducts including fly ash, bottom ash, and gypsum.

Due to the delays in the FGD completion and operation dates, both plants are currently only disposing of fly ash in the landfills.

The Kyger landfill will cover 98 acres when all phases are completed, and have a total air space to hold 20 million cubic yards of coal combustion by-products. This landfill has a 20-year design life, and since only fly ash is currently being placed in the landfill, the 20-year design life would begin when the FGD systems are completed and placed into full operation. OVEC expects the Kyger FGD to begin full operations in 2012 and Clifty in 2013.

The portion of the existing landfill at Clifty that is being upgraded to a Type I Restricted Waste Landfill will cover 109 acres when all phases are completed and will also have the total air space to hold the amount of coal combustion by-products (fly ash, boiler slag, and gypsum) generated at the plant for 20 years from when the FGD system is complete and placed in operation.

OVEC has projected Capital Expenditures of approximately $15 million per year in 2016 and 2017 for phase two and three of the landfills.

Description of cooling towers and date installed

The Kyger and Clifty Creek units use once-through cooling in their steam cycle, therefore neither plant is equipped with a cooling tower.

Clifty Creek

Item	Clifty Unit 1	Clifty Unit 2	Clifty Unit 3	Clifty Unit 4	Clifty Unit 5	Clifty Unit 6
1.a. Commercial Operation Date	2/15/1955	5/1/1955	7/11/1955	10/24/1955	11/30/1955	3/13/1956
1.b. Fuel burned	PRB/NAPP	PRB/NAPP	PRB/NAPP	PRB/NAPP	PRB/NAPP	PRB/NAPP; ILB[1]
1.b. Fuel burned - sulfur content - lb SO2/mmBtu	1.9 - 2.5	1.9 - 2.5	1.9 - 2.5	1.9 - 2.5	1.9 - 2.5	1.9 - 2.5; 5.2
1.c. Heat rate - 2010 net heat rate	10,331	10,075	10,403	10,289	10,253	10,174
1.d. Nameplate generating capacity - MW gross	217.26	217.26	217.26	217.26	217.26	217.26
1.e. Particulate Matter (PM) Emissions Control - Type	EC[2]	EC	EC	EC	EC	EW[3]
1.e. Particulate Matter (PM) Emissions Control - Date	Aug-79	Jun-79	Apr-79	Mar-79	Dec-78	Sep-77
1.e. Sulfur Dioxide (SO_2) Emissions Control - Type	SS[4]	SS	SS	SS	SS	SS
1.e. Sulfur Dioxide (SO_2) Emissions Control - Date	Jan-95	Jan-95	Jan-95	Jan-95	Jan-95	Jan-95
1.e. Nitrogen Oxides (NO_x) Emissions Control - Type	OFA[5] ; SCR[6]	OFA ; SCR	OFA ; SCR	OFA ; SCR	OFA ; SCR	OFA
1.e. Nitrogen Oxides (NO_x) Emissions Control - Date	Mar-99; Jul-03	Oct-99; Apr-03	Feb-99; Jun-03	Nov-98; Jan-03	Oct-98; Nov-02	May-98

1. ILB - Illinois Basin coal currently being tested in Unit 6. ILB is a potential post-FGD coal supply.
2. EC - Electrostatic precipitator, cold side, with flue gas conditioning. SO_3 flue gas conditioning added in 1998.
3. EW - Electrostatic precipitator, hot side, without flue gas conditioning
4. SS - Switch to lower sulfur fuel. Clifty Creek coal yard and boiler modifications to allow higher PRB percentages completed in 1994.
5. OFA - Overfire Air
6. SCR - Selective Catalytic Reduction on all but Unit 6.
7. FGD - Flue Gas Desulfurization
8. FGD Construction - JBR 1-3 in service 4Q 2012
9. FGD Construction - JBR 4-6 in service June 2013

Kyger Creek

Item	Kyger Unit 1	Kyger Unit 2	Kyger Unit 3	Kyger Unit 4	Kyger Unit 5
1.a. Commercial Operation Date	2/15/1955	6/24/1955	9/1/1955	11/15/1955	12/22/1955
1.b. Fuel burned	PRB/NAPP	PRB/NAPP	PRB/NAPP	PRB/NAPP	PRB/NAPP
1.b. Fuel burned - sulfur content - lb SO2/mmBtu	4.2	4.2	4.2	4.2	4.2
1.c. Heat rate - 2010 net heat rate	10,345	10,397	10,327	10,564	10,230
1.d. Nameplate generating capacity - MW gross	217.26	217.26	217.26	217.26	217.26
1.e. Particulate Matter (PM) Emissions Control - Type	EC[1]	EC	EC	EC	EC
1.e. Particulate Matter (PM) Emissions Control - Date	Jun-80	Apr-80	Feb-80	Mar-80	May-80
1.e. Sulfur Dioxide (SO_2) Emissions Control - Type	SS[2]	SS	SS	SS	SS
1.e. Sulfur Dioxide (SO_2) Emissions Control - Date	Jan-95	Jan-95	Jan-95	Jan-95	Jan-95
1.e. Nitrogen Oxides (NO_x) Emissions Control - Type	OFA[3] ; SCR[4]	OFA ; SCR	OFA ; SCR	OFA ; SCR	OFA ; SCR
1.e. Nitrogen Oxides (NO_x) Emissions Control - Date	Nov-98; Oct-02	Jun-98; Dec-02	Nov-99; Feb-03	Feb-99; Apr-03	Oct-95; Jun-03

1. EC - Electrostatic precipitator, cold side, with flue gas conditioning. SO_3 flue gas conditioning added in 2001.
2. SS - Switch to lower sulfur fuel. Kyger Creek coal yard and boiler modifications to allow higher PRB percentages completed in 2006-2007.
3. OFA - Overfire Air
4. SCR - Selective Catalytic Reduction
5. FGD - Flue Gas Desulfurization
6. FGD Construction - JBR 3-5 in service Fall 2011
7. FGD Construction - JBR 1-2 in service Spring 2012

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

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Question No. 8

Witness: Lonnie E. Bellar

Q-8. Provide a detailed description and estimated cost of each capital expenditure, and each operation and maintenance expense, that may be needed for each OVEC generating unit over the next 15 years to meet each of the following: proposed rules for Maximum Available Control Technology for reduction in mercury: the existing regulatory scheme for coal combustion waste, including the date each landfill will reach full capacity and future plans for increased capacity; potential regulatory scheme with coal combustion waste regulated as hazardous waste; potential need for cooling towers; and potential regulation of greenhouse gas emissions.

A-8. Concerning the proposed rule for Maximum Available Control Technology for reducing mercury emissions, it is the Companies' understanding that OVEC proposes to comply with these reduction requirements by the co-benefit mercury reductions on the units at Kyger and Clifty that are equipped with both Selective Catalytic Reduction ("SCR") and jet-bubbling reactor Flue-Gas Desulfurization ("FGD") systems. The FGDs at Clifty and Kyger are presently under construction and expected to be in full service in 2012 for Kyger and 2013 for Clifty Creek. Clifty Creek Unit 6 does not have an SCR, and OVEC has estimated the cost of building an SCR for Clifty Creek Unit 6 at $65 million.

With regard to the existing regulatory scheme for coal combustion waste, please see the relevant portion of the Companies' response to the Commission Staff's DR No. 7.

Concerning the potential regulatory scheme to regulate coal combustion residuals as hazardous waste, OVEC has not projected what the cost of compliance with such a regulatory scheme would be. OVEC has projected it will cost $358 million to comply if the U.S. EPA classifies coal combustion residuals as a solid waste under Subtitle D of the federal Resource Conservation and Recovery Act.

With respect to the potential need for cooling towers, OVEC has projected it will cost $20 million to build a fish collection and return system for the minimization of impingement and mortality of aquatic species to comply with the impingement and entrainment requirements of the newly proposed 316 (b) rule.

Finally, concerning the potential regulation of greenhouse gas emissions, the Companies are not aware of any cost-effective methods for reducing greenhouse gas emissions from existing coal-fired power plants. The Companies and OVEC continue to monitor developments in this area.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 9

Witness: Lonnie E. Bellar

Q-9. Provide copies of any documents, whether in written or electronic format, including but not limited to letters, memoranda, studies, reports, or analyses, prepared by or for OVEC or by or for LG&E or KU which discuss or address OVEC's future capital costs, operations and maintenance expenses, or power costs resulting from compliance with existing, proposed, or suggested environmental requirements.

A-9. Please see the attached OVEC Environmental Compliance Strategy document, which is provided under a petition for confidential protection.

This information is redacted and provided under seal pursuant to a Petition for Confidential Protection.

Pages 1 - 9

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
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Question No. 10

Witness: Lonnie E. Bellar

Q-10. Explain whether LG&E/KU are aware of any environmental compliance issues for the OVEC generation units that will require LG&E/KU financial contributions.

a. If any contributions are projected, provide the date, total investment required, the LG&E/KU investment, and a brief description of the work required.

b. If contributions will be required, explain how the cost thereof will be recovered, both by OVEC and by LG&E/KU.

A-10. The Companies are not aware of any environmental compliance issues for the OVEC generation units that will require financial contributions above and beyond those that are projected to be collected through the ICPA Billable Cost Summary Projections, which are attached hereto and are provided under a petition for confidential protection, and those that are contained in the OVEC Environmental Compliance Strategy document attached to the Companies' response to the Commission Staff's DR No. 9. (The costs contained in the OVEC Environmental Compliance Strategy document are not included in the ICPA Billable Cost Summary Projections.)

This information is redacted and provided under seal pursuant to a Petition for Confidential Protection.

Pages 1 - 2

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 11

Witness: Lonnie E. Bellar

Q-11. Refer to page 7, Item 15, of the March 16, 2011 applications. LG&E/KU request expeditious consideration of the Amended and Restated ICPA.

a. Explain whether any other necessary approvals are contingent upon Commission approval.

b. Explain why the request for approval was not made until March 16, 2011, when the Amended and Restated ICPA is dated September 10, 2010.

A-11. a. Approval is needed from numerous regulatory bodies and other actions must be undertaken and coordinated by OVEC and the Sponsors in order for the ICPA to become effective. Accordingly, LG&E/KU requested the Commission to consider this application as expeditiously as possible. But none of the other necessary approvals is contingent upon the Commission's approval

b. The ICPA had to be unanimously approved by all of the sponsors prior to submittal for regulatory approval. The date of the agreement was set at September 10, 2010, but each sponsor approved and signed their respective ICPA at different times. The final Sponsor did not execute the ICPA until late in the first quarter of 2011.

LOUISVILLE GAS AND ELECTRIC COMPANY

Response to the Initial Information Request of Commission Staff
Dated April 15, 2011

Case No. 2011-00100

Question No. 12

Witness: Lonnie E. Bellar

Q-12. Identify and describe each relevant change in the proposed ICPA from the current ICPA. Include whether the change affects the energy cost to the participating utilities or the costs the participating utilities or the costs the participating utilities will eventually be required to pay.

A-12. Attached is a redlined version of the ICPA showing the changes in the Amended and Restated ICPA from the current ICPA. The most significant changes relate to no longer having to comply with ECAR reserve and reliability requirements, adding a reference to the Reliability*First* Corporation (the successor to ECAR) reliability standard, and some changes in OVEC owners and their ownership shares (the Companies' shares did not change). These changes will not impact the cost of OVEC energy (except insofar as the cost of complying with Reliability*First* requirements differs from the cost of meeting former ECAR requirements). Instead, if the Amended and Restated ICPA receives all the necessary approvals, savings will result from refinancing OVEC debt over a longer term, and that refinancing is not directly referenced in the new ICPA.

Execution Copy

~~COMPOSITE COPY~~

~~OF~~

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF ~~MARCH 13, 2006~~SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
~~THE CINCINNATI GAS & ELECTRIC COMPANY,~~
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

~~COMPOSITE COPY AS MODIFIED BY: Modification No. 1, dated as of March 13, 2006.~~

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of ~~March 13, 2006, including Modification No. 1 to this Agreement, dated as of March 13, 2006 (together,~~ September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), ~~THE CINCINNATI GAS & ELECTRIC COMPANY~~BUCKEYE POWER GENERATING, LLC (herein called ~~Cincinnati~~Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), ~~FIRSTENERGY GENERATION CORP~~DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. (herein called FirstEnergy), INDIANA MICHIGAN POWER COMPANY (herein called Indiana), KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of ~~July 10, 1953~~March 13, 2006, as amended ~~from time to time~~by Modification No. 1, dated as of March 13, 2006 (herein called the ~~Original~~Current Agreement), by and among OVEC~~, Appalachian, Cincinnati, Columbus, Dayton, Indiana, Kentucky, Louisville, Monongahela Ohio Edison Company, Ohio Power, Pennsylvania Power Company, The Potomac Edison Company, Southern Indiana, The Toledo Edison Company and West Penn Power Company~~ and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the ~~Original Agreement was~~Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (~~the Modifications~~together, herein called the Original Agreement); and

~~WHEREAS~~WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio

Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

~~WHEREAS, pursuant to East Central Area Reliability Group ("ECAR") Document No. 2, entitled DAILY OPERATING RESERVE, as revised August 8, 1996 ("ECAR Document No. 2"), Corporation is required to have available spinning reserve equal to a percentage of its internal load as well as supplemental reserve equal to a percentage of its internal load, which supplemental reserve is expected to be provided by the Sponsoring Companies in proportion to their respective Power Participation Ratios as defined in *subsection* 1.0120; and~~

WHEREAS, the parties hereto desire to amend and restate in their entirety, the ~~Original~~Current Agreement~~ and all of the Modifications,~~ to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

~~1.017 "ECAR Emergency Energy" means energy sold by Corporation from its Spinning Reserve during an ECAR Reserve Sharing Period.~~

~~1.018 "ECAR Reserve Sharing Period" means any period of time during which any control area within ECAR ("ECAR Member") is experiencing a system contingency which requires implementation of ECAR's reserve sharing procedures.~~

1.017 ~~1.019~~ "Effective Date" means ~~March 13, 2006,~~ September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement ~~(including Modification No. 1 to this Agreement)~~ have been satisfied in form and substance satisfactory to the Corporation.

1.018 ~~1.0110~~ "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 ~~1.0111~~ "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 ~~1.0112~~ "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 ~~1.0113~~ "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 ~~1.0114~~ "Month" means a calendar month.

1.0113 ~~1.0115~~ "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 ~~1.0116~~ "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

~~1.0117 "OVEC Emergency Energy" means energy purchased by Corporation during an ECAR Reserve Sharing Period pursuant to the provisions of ECAR Document No. 2.~~

1.0115 ~~1.0118~~ "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 ~~1.0119~~ "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 ~~1.0120~~ "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent
Allegheny	~~9.00~~3.01
Appalachian	15.69
~~Cincinnati~~Buckeye	~~9.00~~18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	~~20.50~~9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	~~3.50~~0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

~~1.0121 "Spinning Reserve" means unloaded generation which is synchronized and ready to serve additional demand within ten minutes.~~

~~1.0122 "Supplemental Reserve" means a combination of spinning reserve, qualified interruptible load, qualified quick-start generating capacity or pre-scheduled assistance from another system which can be fully utilized within ten minutes.~~

1.0118 ~~1.0123~~ "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 ~~1.0124~~ "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 ~~1.0125~~ "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 ~~1.0126~~ "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 ~~1.0127~~ "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power~~, ECAR Emergency Energy or OVEC Emergency Energy~~.

ARTICLE 3

~~ECAR AND OVEC EMERGENCY ENERGY~~[RESERVED]

~~3.01. In order to enable Corporation to fulfill its obligation under ECAR Document No. 2 to maintain Supplemental Reserve equal to a percentage of Corporation's internal load, each Sponsoring Company shall stand ready to supply its Power Participation Ratio of OVEC's Supplemental Reserve obligation to other members of ECAR during any ECAR Reserve Sharing Period. It is understood, however, that the amount which each Sponsoring Company may charge for its share of such Supplemental Reserve shall be such Sponsoring Company's FERC filed emergency energy charge.~~

~~3.02. In order to enable Corporation to fulfill its obligation under ECAR Document No. 2 to provide some or all of the energy available from OVEC's Spinning Reserve to an ECAR Member which is in need of ECAR Emergency Energy, the Sponsoring Companies shall stand ready to purchase from Corporation the energy available from its Spinning Reserve, or any portion thereof, for their own emergency use or for resale to or for another ECAR Member which is experiencing an emergency and shall also stand ready to transmit such energy to or for another ECAR Member which is experiencing an emergency.~~

~~3.03. In the event that Corporation is required to purchase, and pay other entities for, OVEC Emergency Energy, each Sponsoring Company shall pay its share, in accordance with its Power Participation Ratio, of the full amount paid by Corporation for OVEC Emergency Energy in accordance with the applicable FERC filed emergency energy charge; provided, however, that Corporation shall credit any payments which Corporation owes to any Sponsoring Company for ECAR Emergency Energy against the amounts otherwise payable by such Sponsoring Company for OVEC Emergency Energy.~~

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under ~~ECAR Document No. 2~~Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* ~~1.0120,~~1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section ~~5.06.~~5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER~~, ECAR AND OVEC EMERGENCY ENERGY,~~ AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge~~ and, if applicable, an emergency energy charge~~, all determined as set forth in this *Article* 5.

5.02. *Energy Charge.* The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and~~ the sum of (i) the total cost of fuel used to generate ECAR Emergency Energy, and (ii)~~ the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section ~~8.04.~~8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge.* During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this

Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of

Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section ~~8.04,~~8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") <u>provided that</u>, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and <u>provided further that</u>, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge*. The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

~~5.05. *ECAR and OVEC Emergency Energy*. The amount to be paid to Corporation for ECAR Emergency Energy supply under this Agreement shall be 98.74 mills per kilowatt hour (plus transmission charges calculated in accordance with applicable law). The amount to be paid to Corporation for OVEC Emergency Energy purchased by Corporation under~~

~~this Agreement shall be the applicable FERC filed emergency energy charge per kilowatt hour (plus any applicable transmission charges calculated in accordance with applicable law).~~

5.05. ~~5.06.~~ *Minimum Loading Event Costs.* To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section ~~5.06~~5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments.* The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

~~8.03. *ECAR and OVEC Emergency Energy.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating all ECAR Emergency Energy supplied to or for the account of such Sponsoring Company during such month and all OVEC Emergency Energy supplied to Corporation during such month, specifying~~

~~the amount due to the Corporation therefor pursuant to *Article* 5 above; provided, however, that Corporation shall credit any payments which Corporation owes to any Sponsoring Company for ECAR Emergency Energy against the amounts otherwise payable by such Sponsoring Company for OVEC Emergency Energy. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for ECAR Emergency Energy or OVEC Emergency Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.~~

8.03. ~~8.04.~~ *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section ~~5.06~~5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. ~~8.05.~~ *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela~~ and~~, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to ~~Cincinnati~~Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and ~~Cincinnati~~Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the ~~Effective Date~~effective date of ~~this~~the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement ~~will be~~were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company ~~will be~~or their predecessors were thereby changed, modified or otherwise removed as of the ~~Effective Date of this~~effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the ~~Effective Date of this~~effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall

~~be~~have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) ~~March 13, 2026~~June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.,* 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.,* 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(b) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver*. Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, provided that, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation, the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10^{th}) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; provided that such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this

Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties.* Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement~~ and on and as of the date of Modification No. 1 to this Agreement~~, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default.* If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[*Signature pages follow*]

IN WITNESS WHEREOF, the parties hereto have caused this Amended and Restated Inter-Company Power Agreement to be duly executed and delivered by their proper and duly authorized officers ~~to be effective~~ as of ~~March 13, 2006.~~September 10, 2010.

OHIO VALLEY ELECTRIC CORPORATION

By ______________________________
Its ______________________________

ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.

By ______________________________
Its ______________________________

APPALACHIAN POWER COMPANY

By ______________________________
Its ______________________________

~~THE CINCINNATI GAS & ELECTRIC COMPANY~~ BUCKEYE POWER GENERATING, LLC

By ______________________________
Its ______________________________

COLUMBUS SOUTHERN POWER COMPANY

By ______________________________
Its ______________________________

THE DAYTON POWER AND LIGHT COMPANY

By ______________________________
Its ______________________________

~~FIRSTENERGY GENERATION CORP~~DUKE ENERGY OHIO, INC.

By ______________________________
Its ______________________________

~~INDIANA MICHIGAN POWER COMPANY~~FIRSTENERGY GENERATION CORP.

By ______________________________
Its ______________________________

~~KENTUCKY UTILITIES~~INDIANA MICHIGAN POWER COMPANY

By ______________________________

~~LOUISVILLE GAS AND ELECTRIC~~KENTUCKY UTILITIES COMPANY

Its ______________________________

By ______________________________
Its ______________________________

LOUISVILLE GAS AND ELECTRIC COMPANY

By ______________________________
Its ______________________________

MONONGAHELA POWER COMPANY

By ______________________________
Its ______________________________

~~MONONGAHELA~~OHIO POWER COMPANY

By ______________________________
Its ______________________________

~~OHIO POWER~~SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

By ______________________________
Its ______________________________

~~SOUTHERN INDIANA GAS AND ELECTRIC COMPANY~~

~~By ______________________________~~
~~Its ______________________________~~

PENINSULA GENERATION COOPERATIVE

By ______________________________

Its ______________________________

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APR 28 2011

PUBLIC SERVICE
COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

VERIFIED APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG TERM PURCHASE CONTRACT	)	**CASE NO. 2011-00099**
VERIFIED APPLICATION OF KENTUCKY UTILITIES COMPANY FOR AN ORDER PURSUANT TO KRS 278.300 AND FOR APPROVAL OF LONG TERM PURCHASE CONTRACT	)	**CASE NO. 2011-00100**

JOINT PETITION FOR CONFIDENTIAL PROTECTION

Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Applicants") hereby petition the Kentucky Public Service Commission ("Commission") pursuant to 807 KAR 5:001, Section 7, and KRS 61.878(1)(c) to grant confidential protection for the items described herein, which the Applicants seek to provide in response to the Initial Information Request of Commission Staff to LG&E Nos. 2, 4, 5, 9, and 10; and Initial Information Request of Commission Staff to KU Nos. 2, 4, 5, 9, and 10. In support of this Joint Petition, the Applicants state as follows:

1. Under the Kentucky Open Records Act, the Commission is entitled to withhold from public disclosure information confidentially disclosed to it to the extent that open disclosure would permit an unfair commercial advantage to competitors of the entity disclosing the information to the Commission. See KRS 61.878(1)(c). Public disclosure of the information identified herein would, in fact, prompt such a result for the reasons set forth below.

2. The confidential information contained in the cited responses includes the operating and maintenance practices LG&E and KU use with their own units (as well as those of

the Ohio Valley Electric Corporation, "OVEC"), LG&E's and KU's variable costs for all of their units and for OVEC, OVEC's environmental compliance strategy (including the costs of compliance), and OVEC's cost projections for the next 30 years. If the Commission grants public access to this information, LG&E and KU could be disadvantaged in the wholesale energy markets by revealing their costs of production (which include OVEC's costs of production) and OVEC could be harmed in environmental compliance contract negotiations for equipment and construction (and LG&E and KU could in turn be harmed if OVEC is harmed in such negotiations). All such commercial harms would ultimately harm LG&E's and KU's customers, who currently benefit—and should continue to benefit for years to come—from the relatively low-cost power OVEC provides.

3. The OVEC-provided information for which the Applicants are seeking confidential treatment is not known outside of OVEC and its owners, and is not disseminated within OVEC and its owners except to those employees with a legitimate business need to know and act upon the information, and is generally recognized as confidential and proprietary information in the energy industry.

4. The LG&E-and-KU-provided information for which the Applicants are seeking confidential treatment is not known outside of LG&E and KU, and is not disseminated within LG&E and KU except to those employees with a legitimate business need to know and act upon the information, and is generally recognized as confidential and proprietary information in the energy industry.

5. Applicants do not object to limited disclosure of the confidential information described herein, pursuant to an acceptable protective agreement, to intervenors with legitimate interests in reviewing the same for the purpose of participating in this case.

6. If the Commission disagrees with any of these requests for confidential protection, however, it must hold an evidentiary hearing (a) to protect the Applicants' due process rights and (b) to supply the Commission with a complete record to enable it to reach a decision with regard to this matter. Utility Regulatory Commission v. Kentucky Water Service Company, Inc., Ky. App., 642 S.W.2d 591, 592-94 (1982).

7. In accordance with the provisions of 807 KAR 5:001, Section 7, LG&E and KU are filing with the Commission one copy of the Confidential Information highlighted and ten (10) copies without the Confidential Information.

WHEREFORE, Louisville Gas and Electric Company and Kentucky Utilities Company respectfully requests that the Commission grant confidential protection to the information designated as confidential for a period of five years from the date of filing the same.

Dated: April 28, 2011

Respectfully submitted,

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