Big Rivers
Electric Corporation
201 Third Street • P.O. Box 24
Henderson, KY 42419-0024

PSC CASE NO. 2007-00455
BIG RIVERS ELECTRIC CORPORATION'S RESPONSES TO AG's INITIAL DATA REQUEST

4 of 4

Item 133) Regarding the "Environmental Matters" and "significant financial impacts on the use of fossil fuels for power generation" referenced in the Big Rivers 2005 Annual Report to Members (Exhibit 41), please provide any documents or studies performed by or for Big Rivers since January 2005 which address and/or estimate costs associated with the Big Rivers generating facilities and compliance with:

a. The EPA's Clean Air Mercury Rule (CAMR);

b. The EPA's Clean Air Interstate Rule (CAIR);

c. Performance goals of the Clean Water Act Section 316(b);

d. Regulation of carbon dioxide as a pollutant under the Clean Air Act; and,

e. Any other state or federal rules likely to cause additional costs in order to meet pollution standards or otherwise comply with those rules.

Response) Please see the attached studies Big Rivers has had performed which address costs associated with environmental compliance issues.

a) Big Rivers has not done nor commissioned any studies specific to compliance with CAMR.

b) Please see the attachments regarding studies specific to compliance with CAIR.

c) Big Rivers has not done nor commissioned any studies specific to compliance with CWA Section 316(b).

d) Please see the attached analyses as well as CRA's CO_2 sensitivity analyses specific to compliance with carbon dioxide (CO_2) capture.

e) Big Rivers has not done nor commissioned any other studies specific to environmental compliance.

Studies:
(1) Global Insight Big Rivers Sept 2007.doc., See AG Item 64;
(2) Annual Output – 12-15-07.xls, see PSC Item 22;
(3) SCI NO_x Review Report 08-09-06.pdf, attached;
(4) Addendum SCI NO_x Reviews 08-09-06.pdf, attached;
(5) CO_2 Tax calcs.xls, attached;
(6) CRA International's CO_2 Sensitivity Analysis.

Witness) David A. Spainhoward

WKE Compliance Plan
Kentucky NO_x SIP Call
Performance Review

Big Rivers Electric Corporation
Henderson, Kentucky

Final
August 2006

CONFIDENTIAL

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

Executive Summary

General

This report presents the results of Stanley Consultants' evaluation of the Western Kentucky Energy (WKE) Compliance Plan for the Kentucky Nitrogen Oxide (NO_x) State Implementation Plan (SIP) Call. This study is based upon the documents, reports and spreadsheets provided by Big Rivers Electric Corporation (BREC) to Stanley Consultants. A summary of these documents and reports are listed in Appendix A.

Purpose

The purpose of this study is to determine the WKE Plan 8A ability to satisfy the needs of the BREC system requirements to comply with the Kentucky NO_x SIP Call regulations. Ultimately, the WKE Compliance Plan 8A should allow the BREC system to "take care of itself" each Ozone Transport Assessment Group (OTAG) season under a range of possible operating scenarios. This evaluation assumed the BREC system would "break even" with respect to NO_x emissions versus available NO_x allowances at the end of an OTAG season considering reasonable and conservative contingencies.

The present value analysis time period studied began in the year 2007 and concluded in the year 2023 which is coincident with the remainder of the operating period of the lease agreement. During the years 2007 and 2008, the plan must satisfy the system operations for the OTAG season only which consists of the five months of May through September. In the year 2009, the plan must satisfy and the BREC system must comply with the new Clean Air Interstate Rule (CAIR) regulations which require among other issues, annual NO_x emissions compliance which extends to the end of the evaluation period.

The WKE Plan 8A failed to meet future projections for NO_x removal and Stanley Consultants identified the necessary additions and/or improvements to modify the performance of WKE Plan 8A. The evaluation includes preparation of conceptual capital cost estimates and a projection of Operation and Maintenance (O&M) costs for each of the three options identified.

Conclusions

The following summary of conclusions is the direct result of this study:

1. WKE Plan 8A includes the use of innovative technologies to achieve NO_x reductions.

2. WKE chose to proceed with WKE Plan 8A. In a letter dated February 19, 2002 WKE agreed to hold BREC harmless for any additional capital or O&M costs that it would be liable for with the installation of the technologies and scope of work as identified in WKE Plan 5B if it had been used to comply with the Kentucky SIP regulation. The limits identified in WKE Plan 5B were budget costs, but as stated in the February 19, 2002 letter, the limit protections were extended to WKE to include actual costs.

3. The upgrade of plant control systems to distributed controls systems (DCS) and neural network (NN) systems will result in additional NO_x control and other advantages will result. However, the control system, analyzers and instruments must be maintained and periodically calibrated. If not, the advantages of the sophisticated digital control and neural network systems will be lost. Upon review of the WKE reported NO_x emissions rates, the systems may not be optimally tuned.

4. Contingency cost estimates were eliminated from WKE's compliance plan cost projections. Stanley Consultants typically adds ten percent of a project capital cost for contingencies.

5. The impact of unit starts on NO_x allowance consumption was not included in the Power Technology review, Sargent & Lundy (S&L) Report nor considered by WKE.

6. All units are assumed to be 100 percent available during the OTAG season. This availability was an incorrect assumption, as evidenced by forced outage causes and planned outage events and the additional NO_x emissions which are a result of these events. Refer to Appendix C which documents the forced outage causes and planned outage events. Refer to Table 5-9 which documents the additional NO_x emissions.

7. The Henderson Municipal Power and Light (HMPL) units would utilize SCR/DCS/NN/BOP to achieve 90 percent NO_x reduction in the WKE Plan 8A and 5B. This information was obtained from the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001. The WKE Plan 8A and 5B spreadsheets note the HMPL Units 1 and 2 would utilize Selective Catalytic Reduction (SCR) systems to achieve 90 percent NO_x reduction. The noted differences could result in a flaw in the WKE Plan 8A or 5B.

8. The lack of availability of the units which were retrofitted with SCR units is due in part to the corrosion in the air heaters and associated ductwork or due to air heaters plugging from sulfuric acid and calcium sulfate attack.

9. Upon review of the WKE NBV and CWIP report, Stanley Consultants concludes that not all of the neural network systems have been installed. Refer to Table 2-5.

10. WKE Plan 8A failed to perform as predicted based on differences in specific unit heat rates, differences in specific unit emission rates, additional NO_x emissions due to other events, and planned and forced outages. Specifically, the Coleman Units did not achieve the NO_x reduction efficiencies as noted in the settlement agreement between WKE and Mobotec. An alternate SNCR control strategy was offered by Mobotec to WKE for implementation on the Coleman Unit(s) in recognition of the need to further reduce NO_x emissions. Refer to Table 3-9 and 3-10.

11. WKE Plan 5B would provide for compliance during the 2004 and 2005 OTAG seasons as additional NO_x emissions would be removed due to the installation of SCRs on the Green Units. Refer to Table 4-4 and 4-5.

12. Additional NO_x control technologies will need to be installed on the Green units to remove additional NO_x emissions to ensure future system compliance with the current allocation of NO_x allowances. Refer to Table 6-3 and 6-4.

13. Green Units 1 and 2 SCR system construction costs in 2006 dollars are estimated as follows:

a.	Green Unit 1 – 231 Megawatt (MW) unit	$53,848,000
b.	Green Unit 2 – 223 MW unit	$48,216,000

    (1) 2009 O&M costs for the SCR systems are as follows:

        (a) Annual Fixed O&M – $534,000 for Green Unit 1 and $523,000 for Green Unit 2.

        (b) Annual Variable O&M – $1,093,000 for Green Unit 1 and $1,118,000 for Green Unit 2.

Recommendations

The following recommendations are made as a result of this study:

1. BREC should consider several options to determine the best plan to meet future NO_x compliance. These options are presented below in order of least risk to maximum exposure.

    a. Option 1 presents the least risk exposure which may result from operational events and results in excess allowances which can be banked or sold even in the worst case scenario. Option 1 includes the installation of SCRs and subsystems on both Green Units. The system costs include ammonia unloading and storage, economizer modifications, induced draft fan modifications, and air heater enameled basket modifications. The estimated capital cost for this option is $102,064,000. The present value annual cost associated with this option is $85,822,592. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

(1) The addition of SCR(s) and subsystems to the Green Unit(s) will result in a co-benefit reduction of mercury emissions. The EPA issued the Clean Air Mercury Rule (CAMR) on March 15, 2005 to permanently cap mercury emissions and consists of two phases. The Phase I cap commences in 2010. The intent of the Phase I cap is to achieve mercury emissions reductions through the operation of existing air pollution control devices (SCR, precipitators, and FGD). The co-benefit reduction of mercury emissions could generate a revenue stream from mercury credits which would be sold on the open market during Phase I. The analysis of this revenue stream is outside the scope of this report and would require sensitivity studies of both price and mercury emissions removal efficiencies by the various technologies. Phase II begins in 2018 and establishes a lower limit of mercury emission. This lower limit may require additional control measures which may include the installation of equipment and systems to control mercury emissions.

(2) The addition of SCRs and subsystems on the Green Units would assure system compliance with CAIR Annual NO_x requirements and allow for a revenue stream if excess allowances are sold.

(3) The installation of SCRs and subsystems on both Green Units reduces the risk to BREC in the event of a SCR failure at either of the HMPL Units or the Wilson Unit.

b. Option 2 represents the next least risk exposure. Option 2 will generally cover the NO_x allowances needed in the sensitivity analysis, a small purchase of allowances may be necessary in the worst case scenario. Option 2 includes installation of a SCR and related subsystems on Green Unit 1. The capital costs include ammonia unloading and storage, economizer modifications, induced draft fan modifications, and air heater enameled basket modifications. The estimated capital cost for the SCR portion of this option is $53,848,000. Also included in the Option 2 capital costs are the installation of additional neural network systems at an estimated capital cost of $2,223,000. These control systems were added to aid in the support of NO_x removal. These systems were not included in the Option 1 as Option 1 would produce less tons of emissions than the allowance tons under all operating scenarios. This same condition is not true under Option 2. Under certain operating scenarios, more emissions were generated than the allowances available. Therefore, to reduce the additional risk associated with allowance purchases, the control systems were installed. The total capital cost for this option is $56,071,000. The present value analysis Option 2A includes the sale of allowances generated after the installation of the SCR and subsystems. This analysis does not account for a major event occurrence, for example, the Wilson Unit were available only 50 percent of the OTAG season. Option 2A present value annual costs are $49,176,373. Present value analysis Option 2B evaluates the purchase of allowances if a major event (such as the Wilson Unit were available only 50 percent of the OTAG season) were to occur. Option 2B present value annual costs are $57,793,767. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

(1) Co-benefit mercury removal would be realized with the installation of an SCR and subsystems on Green Unit 1 which would enhance BREC's position relative to mercury emissions reduction but to a lesser degree as provided by Option 1. The co-benefit reduction of mercury emissions could generate a revenue stream from mercury credits which would be sold on the open market during Phase I. The analysis of this revenue stream is outside the scope of this report and would require sensitivity studies of both price and mercury emissions removal efficiencies by the various technologies.

(2) The installation of a SCR and associated subsystems on Green Unit 1 reduces the risk for but will not assure under all operational conditions studied, system compliance with CAIR Annual NO_x requirements. In the event of a failure of either of the HMPL Units or the Wilson Unit SCRs, it is possible that NO_x allowances would need to be purchased to satisfy annual NO_x requirements. This will place BREC under the market forces of pricing and availability for NO_x allowances which may have similar variability as experienced with trading of SO_2 allowances.

c. Option 3 represents the maximum exposure caused by any operational event. Option 3 relies completely on the purchase of additional NO_x allowances and assumes the continuation of the current WKE Plan 8A. For the period of 2009-2023, the estimated cost of the purchase of approximately 849 to 1,703 tons of NO_x allowances ranges from $951,729 to $4,499,326 annually. The present value analysis Option 3A includes the purchase of additional NO_x allowances. This analysis does not account for a major event occurrence, for example, the Wilson Unit were available only 50 percent of the OTAG season. Option 3A present value costs are $13,644,261. Present value analysis Option 3B evaluates the purchase of allowances and accounts for a major event occurrence. Option 3B present value costs are $24,356,422. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

   (1) Option 3 represents the maximum exposure to the risks of variable market availability and pricing of NO_x allowances, similar to the variability experienced with trading of SO_2 allowances.

   (2) In addition, Option 3 does not allow for any co-benefit reduction of mercury emissions.

2. The NO_x removal equipment on Coleman Units 1, 2 and 3, Green Units 1 and 2, HMPL Units 1 and 2, Wilson, and Reid Unit 1 need to be tuned to achieve their optimal removal efficiencies.

3. A Continuous Emissions Monitoring System (CEMS) NO_x analyzer is needed in the HMPL bypass ductwork or stack.

4. Install a neural network system on Coleman Units 1 and 3, HMPL Units 1 and 2, and Wilson unit.

5. Improve the specific unit's heat rate.

6. Reduce the unit's forced outages.

7. Utilize a coal which more closely resembles the design fuel for the various steam generators.

Respectfully submitted,

Stanley Consultants, Inc.

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Reviewed by Ray R Walters
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APPENDICES

Section 1

Introduction

General

Stanley Consultants' performed an evaluation of the existing Western Kentucky Energy (WKE) NO_x Compliance Plan 8A (WKE Plan 8A) and the alternate NO_x Compliance Plan 5B (WKE Plan 5B). The purpose of the evaluation was to determine the ability of WKE Plan 8A to satisfy the NO_x emission requirements of the Big Rivers Electric Corporation (BREC) system in compliance with the Kentucky NO_x SIP Call Regulations both for the previous and the future OTAG seasons. The WKE Plan 8A was evaluated as unsatisfactory to meet the future BREC system requirements, operational criteria, and contingencies; Stanley Consultants identified the appropriate steps to improve the system compliance. The evaluation performed on WKE Plan 5B was to determine the past performance for the previous OTAG seasons had the WKE Plan 5B been implemented.

The scope of work for this project included:

- Review of all NO_x related correspondence in Stanley Consultants' files, including correspondence with WKE, third-party reports, and meeting notes. Stanley Consultants reviewed the recommendations to WKE resulting from the Sargent & Lundy (S&L) report of 1999 and PowerGen's (via PowerTech) comments. The differences in the recommendations and the NO_x compliance strategies implemented by WKE were identified. An attempt was made to quantify and/or describe the WKE assumptions used in the WKE Plan 8A.

- An evaluation of both WKE Plan 8A and the WKE Plan 5B utilizing the operational data collected over the past two (2) OTAG seasons of 2004 and 2005. Information provided to BREC and Stanley Consultants at the NO_x Compliance Review Meeting of January 5, 2006, will be utilized in the review. The WKE Plan 8A's performance, including a description of how and when actual performance conditions varied from WKE Plan 8A assumptions was prepared.

- A determination of projected NO_x emissions for the future OTAG seasons of 2007 and 2008. An evaluation of these projections utilizing the WKE Plan 8A Excel spreadsheet model determined if the projections would satisfy the future BREC system NO_x compliance needs. Sensitivity analyses were performed to aid in identification of future operational exposures.

- Stanley Consultants identified the additions and/or improvements to modify the WKE Plan 8A for future compliance of the BREC system with the Kentucky NO_x SIP Call Regulations. Capital and operational and maintenance (O&M) costs for the additions and/or improvements were identified. A present value economic analysis was then performed which utilized the data developed for the capital and O&M costs for the options identified.

This report summarizes the results of the engineering evaluations described above. The following summaries of each report section describe the content within that section.

- Section 2 entitled "Background Report Review" identifies the various plans developed for and subsequently modified and presented by WKE to BREC. This section of the report defines the decisions made by both WKE and the actions taken by BREC as it applies to implementation of WKE Plan 8A.

- Section 3 entitled "Existing WKE Plan 8A Performance Review" identifies the actual performance of the NO_x reduction systems and equipment installed as identified in Section 2. The evaluation included a comparison of the predicted performance to the NO_x emissions reported and identified any assumptions and abnormal operating conditions affecting the WKE Plan 8A's performance. Assumptions reviewed consisted of emission rates, heat rate and gross capacity factor. Additional operating conditions reviewed were available hours, unit starts and other operational abnormalities which consumed NO_x allowances.

- Section 4 entitled "Alternative NO_x Compliance – WKE Plan 5B Review" identifies the projected performance of the NO_x reduction systems and equipment that would have been installed. The evaluation included an evaluation of the predicted performance to the NO_x emissions reported and identified any assumptions utilized in the development of WKE Plan 5B. Abnormal operating conditions affecting the performance of WKE Plan 5B were also reviewed. Assumptions reviewed consisted of emission rates, heat rate and gross capacity factor. Additional operating conditions reviewed were available hours, unit starts and other operational abnormalities which consumed NO_x allowances.

- Section 5 entitled "WKE Plan 8A – Future Performance" identifies the projected performance of the NO_x reduction systems and equipment installed as identified in Section 2 for future OTAG season compliance. Stanley Consultants evaluated the existing WKE Compliance Plan 8A to determine if the plan will allow the BREC system to "take care of itself" each OTAG season under a range of possible operating scenarios. The evaluation assumed that the BREC system is to "break even" with regard to tons of NO_x emitted versus available NO_x allowances at the end of an OTAG season considering reasonable, conservative contingencies. Stanley Consultants reviewed past generation capacity factors, availability factors and heat rate information provided by WKE from previous Annual Condition Assessment Reports. This information was utilized to develop future anticipated capacity and availability factors and heat rate impacts for evaluation of future compliance. In addition, the anticipated future planned and unplanned outages provided by BREC were reviewed to determine the effect to capacity and availability factors and heat rates of the units. Finally, sensitivity analyses were performed to aid in identifying any future operational exposures. Any allowance deficit identified was converted into a cost exposure.

- Section 6 entitled "NO_x Compliance Plan – Future Improvements" identifies the additions and improvements to enhance the projected performance of the NO_x reduction systems and equipment to be installed as a modification to WKE Plan 8A. The criterion utilized is the development of a plan which will result in a scenario that would have sufficient allowances to result in a net balance in the future OTAG seasons considering reasonable and conservative contingencies. The capital cost for the additions and improvements were identified. Additionally, the O&M costs were developed from well documented sources. These costs were then utilized in an present value economic analysis. Additional risks associated with each option were also identified and noted.

- Section 7 entitled "Conclusions and Recommendations" summarizes all of the conclusions of the previous sections.

Section 2

Background Report Review

Introduction

Stanley Consultants reviewed the following documents provided by BREC as they relate to the NO_x Compliance Plans developed by WKE.

- Correspondence
- Letter reports
- Third-party reports received from WKE
- Actual NO_x emissions information received from WKE
- NBV and CWIP reports received from WKE
- Unit outage reports received from WKE

The recommendations made to WKE as documented in the 1999 Sargent & Lundy (S&L) report and the comments made by Power Gen (via Power Technology) to the WKE developed NO_x Compliance Plans are analyzed and the differences are noted.

Stanley Consultants utilized the WKE Plan 8A spreadsheet in the evaluation of the past OTAG seasons of 2004 and 2005 to determine compliance.

The following subsections document Stanley Consultants' findings.

S&L Report Review

S&L completed a NO_x Compliance Study for WKE in June, 1999. The study was performed to specifically address the application of selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) technologies at each of the BREC and HMPL generating units. The S&L report documented the development of the NO_x control plans with the associated conceptual cost estimates.

S&L Compliance Strategies

Table 2-1 summarizes the results from the S&L report:

S&L Study Assumptions

The following study assumptions were identified in the S&L 1999 NO_x Compliance Study.

1. The S&L report indicates the annual capacity factor for all units is 90 percent, with the exception of Reid Unit 1 and the Reid combustion turbine (CT). Reid Unit 1 utilized a 50 percent annual capacity factor. The Reid CT utilized a 50 percent annual capacity factor in the Base Case and a 20 percent annual capacity factor in the 5 Percent Margin and the Alternative cases. The S&L report does not indicate if these factors are gross capacity factors or gross output factors.

2. Forced outage rates were not considered for any of the units.

3. Accommodate a broad range of fuel characteristics and SCR catalyst design philosophies through the use of:

   - A relatively low velocity to accommodate high-ash fuels

   - An additional catalyst layer to accommodate the uncertainty resulting from poisoning of the catalyst due to the sulfur dioxide (SO_2) levels and fuel arsenic levels.

4. SCR variable O&M costs included the cost for catalyst replacement, ammonia consumption, and auxiliary power.

5. Fixed O&M costs included maintenance, material, and labor.

6. No additional operating personnel were assumed to be required for any NO_x control candidate technology. Current staff would need to be trained on the operation of the SCR system and the safe handling of the ammonia system. Training costs were not included in the study.

Table 2-1 S&L Selected NO_x Reduction Technologies

Unit	Base Case[1]				5% Margin Case[2]				Alternative Case[3]			
	Technology	Initial NO_x lb/mmBtu	Emissions after Control lb/mmBtu	Removal Efficiency	Technology	Initial NO_x lb/mmBtu	Emissions after Control lb/mmBtu	Removal Efficiency	Technology	Initial NO_x lb/mmBtu	Emissions after Control lb/mmBtu	Removal Efficiency
Coleman Unit 1	NN/SNCR	0.489	0.325	33.54%	NN/SNCR	0.489	0.325	33.54%	NN/SNCR	0.489	0.325	33.54%
Coleman Unit 2	SNCR	0.433	0.320	26.10%	None	0.433	0.433	0.00%	SNCR	0.433	0.320	26.10%
Coleman Unit 3	NN/SCR	0.494	0.070	85.83%	NN/SCR	0.494	0.070	85.83%	NN/SNCR	0.494	0.325	34.21%
HMPL Unit 1	NN/SCR	0.50	0.071	85.80%	NN/SCR	0.500	0.071	85.80%	NN/SCR	0.500	0.071	85.80%
HMPL Unit 2	NN/SCR	0.483	0.069	85.71%	NN/SCR	0.483	0.069	85.71%	NN/SCR	0.483	0.069	85.71%
Green Unit 1	LNB/SCR	0.433	0.050	88.45%	SCR	0.433	0.065	84.99%	LNB/SCR	0.433	0.050	88.45%
Green Unit 2	LNB/SNCR	0.433	0.240	44.57%	SCR	0.433	0.065	84.99%	LNB/SCR	0.433	0.050	88.45%
Wilson Unit	LNB/SCR	0.499	0.069	86.17%	SCR	0.499	0.075	84.97%	LNB/SCR	0.499	0.069	86.17%
Reid Unit 1	LNB/SNCR	0.805	0.480	40.37%	LNB/SNCR	0.805	0.480	40.37%	LNB/SNCR	0.805	0.480	40.37%
Reid CT	Water Injection	0.890	0.220	75.28%	Water Injection	0.890	0.220	75.28%	Water Injection	0.890	0.220	75.28%
Target NO_x	4,574	---	---	---	4,334	---	---	---	Close to 5% Margin Case	---	---	---
NO_x Emissions, tons	4,543	---	---	---	4,300	---	---	---	4,459	---	---	---
Capital Cost, $1,000,000	182	---	---	---	198	---	---	---	180	---	---	---
Present Value Cost $1,000,000	291	---	---	---	307	---	---	---	299	---	---	---

Notes:

(1) The base compliance strategy was developed based on the tons of NO_x reported by EPA in the Kentucky SIP Call. For the base-case strategy, the total ton allocation of 4815 was reduced by 5 percent to 4574 tons to represent the anticipated Kentucky SIP distribution reduction as the mechanism for addressing future industrial growth in the State of Kentucky.

(2) An additional 5 Percent Margin case compliance strategy was developed to address uncertainties such as the installation of future combustion turbines (CTs) in the WKE system, unforeseen performance limitations with the applied combustion modification technologies, and possible revisions to base year determination of allowances. The resulting NO_x emission tons available associated with a 5 Percent Margin scenario is 4334 tons. A 5 Percent Margin compliance strategy would also support a 20 percent annual capacity factor for the Reid CT and the elimination of the installation of a SNCR from the Reid Unit 1.

(3) An Alternative case, which also considers a 5 percent margin, was developed to aid in the evaluation of not installing a SCR at Coleman Unit 3 and retrofitting SNCRs at all Coleman units. The NO_x allowances generated will be approximately 125 tons lower than required to comply with the Kentucky SIP regulations of 4334 tons.

S&L Sources of Data

The following sources of data were utilized in the S&L NO_x Compliance Study.

1. S&L engineers gathered site specific data during the visits to the BREC and HMPL facilities. This information was used in the final sizing and cost estimating of the technologies proposed in the study. Specific information gathered consisted of:
    a. Identify and quantify the estimated capital and O&M costs and performance expectations for each NO_x control technology considered.
    b. Identify specific information regarding the technical viability of various NO_x control technologies for each unit.
    c. Obtain unit data for ancillary components such as induced draft fans, air heaters, and ash handling system.
    d. Identify potential locations for the ammonia storage facilities.
2. WKE supplied data consisted of:
    a. Fuel analysis
    b. Furnace parameters
    c. Equipment capacities and/or limitations
    d. Operating and performance data
    e. Annual and seasonal emissions data
    f. Dispatch data which included future Load Distribution Profile (LDP) spreadsheets for the year 2003
    g. Plant arrangement

S&L Methodology

S&L utilized the Electric Power Research Institute (EPRI) Clean Air Technology (CAT) Workstation which is a comprehensive planning tool to determine the most economical strategy for reducing system-wide emissions. The CAT Workstation was a jointly developed software program prepared by S&L and EPRI.

S&L Recommendations

Based on the compliance strategies developed, S&L recommended the Alternative case noted in Table 2-1 above. This case would result in compliance with the Kentucky NO_x SIP regulations with a 5 percent margin. The 5 Percent Margin would provide a contingency for operational anomalies or other compliance issues. The Alternative case recommendation is summarized as follows.

1. Installation of SCRs at Wilson, both of the Green Units, and both of the HMPL Units.

2. The installation of SNCRs on the Reid Unit 1 and the three Coleman units.

3. The purchase of 125 tons of NO_x allowances per year.

WKE Implementation Plan

Introduction

The S&L NO_x Compliance Study Report was completed and delivered to WKE in June 1999.

Stanley Consultants attended a meeting on April 17, 2000, which included representatives from BREC, WKE, D. B. Riley, Inc. and Duke/Fluor Daniel. A representative for the City of Henderson (HMPL Station II) was not present at this meeting. The design/build consortium of D. B. Riley and Duke/Fluor Daniel was proposed by WKE for the installation of SCR systems. The meeting included several discussions of NO_x control technologies.

In a joint meeting with BREC, HMPL, and Stanley Consultants representatives on April 18, 2001, additional and updated compliance plans were presented by WKE. The compliance plans would reduce the NO_x emissions from 14,000 tons to less than 3,600 tons during the OTAG season beginning in May 2004. The presentation began with the plans developed by S&L. WKE utilized S&L's model to create and analyze additional NO_x compliance plans. These plans utilize a combination of combustion modifications, control system upgrades, SCR systems, and other developing NO_x reduction control technologies.

The plans were subsequently modified by WKE based on comments provided by BREC. The plans were resubmitted for review on April 25, 2001. The plans at that time included the installation of five (5) SCRs in addition to a combination of combustion modifications. The plan also included the installation of neural networks and distributed control systems and alternative NO_x reduction control technologies. This plan was identified as Plan 5 which resulted in the maximum control of NO_x reductions and was the least cost solution.

The compliance strategy was developed based on the tons of NO_x allotted by EPA in the NO_x SIP Call. The total NO_x season credit allotment utilized in the WKE NO_x compliance plans was 4,571 tons and was derived as noted in the following sentences. The total system tons of 4,811 tons calculated in the WKE Plan 8A spreadsheet was based on the 1996 heat input (mmBtu) by unit projected to the expected 2007 heat input (mmBtu) by unit at an emissions rate of 0.15 lb/mmBtu. The total ton allocation of 4,811 was further reduced by 5 percent to 4,571 which represents the anticipated SIP distribution reduction. This reduction was the mechanism anticipated for addressing future industrial growth in the State of Kentucky.

A description of the WKE NO_x Compliance Plans presented at the April 25, 2001 meeting follows:

Description of WKE NO_x Compliance Plans

Plan 5

Plan 5A was the base compliance plan proposed by WKE with a capital cost of $143.6 million dollars. WKE Plan 5A with updated cost estimates of $170.5 million dollars was later called WKE Plan 5B. A copy of the spreadsheet utilized in the development of the WKE Plan 5B is included in Appendix F. This plan included the installation of five SCR systems on the following units: Wilson, both Green units, and both HMPL units. The plan included the conversion of the Reid Unit 1 from a coal fired unit to a co-fired unit utilizing both natural gas and coal. The Reid CT would be operated with natural gas instead of No. 2 oil during the OTAG season. All three of the Coleman units, both of the HMPL units, both of the Green units, and the Wilson unit would receive control system upgrades which included DCS and neural network systems. The projected NO_x removal efficiencies utilized in the calculation of emission values in the WKE Plan 5B model run and methods of reduction for this plan were:

- Wilson Unit – The method of reduction chosen was SCR/DCS/NN/Balance of Plant (BOP) instrumentation resulting in a combined 90 percent removal efficiency.

- Green Units 1 and 2 – The method of reduction chosen was SCR/DCS/NN/BOP resulting in a combined 90 percent removal efficiency.

- HMPL Units 1 and 2 - The method of reduction chosen was SCR/DCS/NN/BOP resulting in a combined 90 percent removal efficiency as noted in the WKE Plan 5B spreadsheet. In contrast, the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001 noted the HMPL Units 1 and 2 method of reduction chosen was SCR/DCS/NN/BOP and no removal efficiency was noted.

- Coleman Units 1, 2, and 3 – The method of reduction chosen was DCS/NN/Field Devices resulting in a combined 10 percent removal efficiency.

- Reid Unit 1 – The method of reduction chosen was to switch to co-firing of natural gas with coal (50 percent gas fired) resulting in a 81.71 percent removal efficiency. The expected NO_x reduction from 0.812 lb/mmBtu on coal fuel only to 0.15 lb/mmBtu when co-firing would result.

- Reid CT - The method of reduction chosen was to install burners capable of firing either No. 2 fuel oil or natural gas. Burning gas during OTAG season will result in a 83.15 percent removal efficiency.

The WKE model run assumptions result in an annual system NO_x emissions projection of 4,488 tons. This level of NO_x emissions complies with the Kentucky SIP regulation allotment of 4,571 tons with 83 allowances or 2 percent in excess. This excess amount could be banked for future year use or sold on the allowance trading market. Actual plant operating and emissions data for the first quarter of 2001 and the years of 2000 and 1997 were utilized as baseline data to determine the modeled emission results for the non-OTAG season. The year 1997 results represent the last full year the generating units were operated by BREC. Table 2-2 summarizes the results from WKE Plan 5B:

Table 2-2 WKE Plan 5B Selected NO_x Reduction Technologies

	WKE Plan 5B			
Unit	**Technology**	**Year 2000 Average NO_x lb/mmBtu**	**Emissions after Control lb/mmBtu**	**Removal Efficiency**
Coleman Unit 1	DCS/NN/Field Devices	0.420	0.378	10.00%
Coleman Unit 2	DCS/NN/Field Devices	0.428	0.385	10.00%
Coleman Unit 3	DCS/NN/Field Devices	0.417	0.375	10.00%
HMPL Unit 1 (1)	SCR/BOP	0.457	0.046	90.00%
HMPL Unit 2 (1)	SCR/BOP	0.478	0.048	90.00%
Green Unit 1	SCR/DCS/NN/BOP	0.412	0.041	90.00%
Green Unit 2	SCR/DCS/NN/BOP	0.422	0.042	90.00%
Wilson Unit	SCR/DCS/NN/BOP	0.431	0.043	90.00%
Reid Unit 1	50% Gas Fired	0.812	0.149	81.71%
Reid CT	Gas Fired	0.890	0.150	83.15%
Target NO_x	4,571	---	---	---
NO_x Emissions, tons	4,487	---	---	---
Capital Cost, $1,000,000	170.5	---	---	---

Notes:
(1) The NO_x reduction technologies listed in this table for HMPL Unit 1 and HMPL Unit 2 were taken from the WKE Plan 5B spreadsheet.

Plan 6

Plan 6 utilizes the same control strategies as WKE Plan 5B, with the exception that the SCR systems and control system upgrades were eliminated from the HMPL Units 1 and 2. The first quarter of 2001 plant performance and emissions data were utilized as the baseline data in the development of the plan. This plan resulted in a negative NO_x season balance of 467 tons per year, indicating the BREC and HMPL Units 1 and 2 would not be in compliance with the Kentucky SIP regulations. The purchase of NO_x emission allowances and/or over-control of NO_x from other BREC units would be necessary for compliance under this scenario.

Plan 7

Plan 7 projects the NO_x emissions from the HMPL Units 1 and 2 independently of the BREC units. With the installation of SCR systems and control system upgrades on the HMPL Units 1 and 2, the NO_x reductions were estimated to achieve 90 percent, resulting in sufficient emission credits to aid in the offset of the excess emissions from the BREC units. To achieve the relative NO_x emission limit of 0.15 lb/mmBtu, the HMPL Units 1 and 2 would need to reduce emissions by 71 percent from existing levels. To achieve 90 percent removal, the capital costs for installation of the SCR systems and O&M expenses for the HMPL Units 1 and 2 would increase resulting in the development of emission credits for the BREC units,. HMPL would request compensation from WKE for the higher capital and O&M costs.

Plan 8A

Plan 8A represents the WKE implementation of developmental NO_x control technologies. A copy of the spreadsheet utilized in the development of the WKE Plan 8A is included in Appendix E. WKE Plan 8A utilized advanced over-fire air (AOFA) and staged combustion NO_x control technologies that were considered to be developmental at the time.

The three Coleman units would utilize AOFA technology and control system upgrades. The two Green units would install coal re-burn technology and control system upgrades. Both systems were projected to achieve 50 percent NO_x reductions.

Per the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001, the HMPL and Wilson units would utilize SCR systems and control system (DCS/NN/BOP) upgrades to achieve 90 percent NO_x reduction.

The Reid Unit 1 would be converted to co-fire natural gas and coal and the Reid CT would operate utilizing natural gas. Annual system NO_x emissions were projected to be 4,534 tons per year, with WKE's model assumptions. These NO_x emissions which comply with the Kentucky SIP regulations allotment of 4,571 tons will generate 37 additional allowances (less than 1 percent) which could be sold or banked. Table 2-3 summarizes the results from WKE Plan 8A:

Table 2-3 WKE Plan 8A Selected NO_x Reduction Technologies

Unit	Technology	Year 2000 Average NO_x lb/mmBtu	Emissions after Control lb/mmBtu	Removal Efficiency
Coleman Unit 1	OFA/DCS/NN/Field Devices	0.420	0.223	47.00%
Coleman Unit 2	OFA/DCS/NN/Field Devices	0.428	0.227	47.00%
Coleman Unit 3	OFA/DCS/NN/Field Devices	0.417	0.221	47.00%
HMPL Unit 1	SCR(1)	0.457	0.046	90.00%
HMPL Unit 2	SCR(1)	0.478	0.048	90.00%
Green Unit 1	Coal Reburn/DCS/NN/BOP	0.412	0.206	50.00%
Green Unit 2	Coal Reburn/DCS/NN/BOP	0.422	0.211	50.00%
Wilson Unit	SCR/DCS/NN/BOP	0.431	0.043	90.00%
Reid Unit 1	50% Gas Fired	0.812	0.149	81.71%
Reid CT	Gas Fired	0.890	0.150	83.15%
Target NO_x	4,571	---	---	---
NO_x Emissions, tons	4,534	---	---	---
Capital Cost, $1,000,000	143.6	---	---	---

Notes:
(1) The NO_x reduction technologies listed in this table for HMPL Unit 1 and HMPL Unit 2 were taken from the WKE Plan 8A spreadsheet. Refer to Appendix E.

Plan 9

Plan 9 was developed by WKE as a baseline model, which calculates the amount of emission allowances that would need to be purchased, 9643 tons, if no additional NO_x emission reduction strategies were installed on the Coleman, HMPL, Wilson, and Green units. This plan accounts for the NO_x reduction resulting from the existing low NO_x burners. The Reid Unit 1 would install NO_x reduction strategies similar to the other plans. Based on a cost of $2,500 per ton of credit, the annual cost to purchase emission credits would result in over $24 million dollars.

On August 17, 2001, a NO_x compliance plan update was presented at a joint meeting with BREC, HMPL, Stanley Consultants, and Burns & McDonnell representatives. The WKE model runs analyzed the compliance options in an effort to fine tune the details for NO_x compliance. The previous plan proposed by WKE on April 25, 2001, was identified as the Base Case compliance Plan 5A resulting in the least cost, least risk plan. Plan 5A results in a capital cost of $143,600,000. Plan 5A was updated with current cost estimates which resulted in a plan cost of $170,500,000 and was labeled Plan 5B.

On August 27, 2001, WKE presented Plan 8A as the NO_x compliance plan which was updated with current cost estimates and resulted in a plan cost of $143,600,000. WKE Plan 8A employed emerging NO_x reduction control technologies and was identified as the least cost, with an associated higher risk compared to WKE Plan 5B. WKE proposed the implementation of Plan 8A for the system wide reduction of NO_x emissions. This plan would reduce the total number of SCR systems installed from five (as identified in WKE Plan 5B) to three SCR systems. Table 2-4 compares the WKE Plan 5B and 8A.

On November 29, 2001, BREC forwarded a letter to WKE regarding the implementation of the WKE revised Plan 8A for reducing NO_x emissions. BREC recognized in this letter that the WKE Plan 8A had the potential for capital and O&M cost savings. BREC stated "Big Rivers feels it is not advisable to proceed with new technologies, despite the cost savings between the previous and current proposed emission control plan is only $26.9 million, less than 16 percent, and without contingencies. This seems to be a relatively small additional price for the SCR systems under Plan 5B with the accompanying proven performance; and the broader margin for error of the plan for meeting emission limits" and "For the reasons stated above Big Rivers cannot approve Plan 8A."

On February 19, 2002, WKE responded to BREC's letter dated November 29, 2001 concerning the NO_x compliance plan stating "We wish to proceed with Model 8A as discussed in the December 2001 Operation Committee meeting. During that meeting, WKE committed to providing a restatement of the last complete paragraph on page two of the referenced letter. The intent of this discussion and agreement is to protect Big Rivers from paying for two separate technologies in the event the technology identified as Model 8A does not perform as intended." The following paragraph was offered in the WKE letter dated November 29, 2001 as a methodology to protect BREC. "Western Kentucky Energy wishes to proceed with Model 8A and agrees that it would hold Big Rivers harmless for any additional capital or O&M costs beyond those that it would have been liable for as described by the technology and scope of work of Model 5B should Model 5B have been chosen as the SIP Call compliance strategy. These limits are shown in the model as budgeted costs, but the limits shall extend to actual costs. In the event that Model 5B is reestablished as the compliance strategy, this agreement excludes any costs associated with inflationary increases or cost increases associated with actual work performed to implement Model 5B verses the budgeted amount for model 5B."

Table 2-4 Comparison of WKE Plan 5B & 8A

Unit	WKE Plan 5B				WKE Plan 8A			
		NO$_x$ Emission Rate				NO$_x$ Emission Rate		
	Technology	Year 2000 Average lb/mmBtu	Emission Rate after Control lb/mmBtu	Removal Efficiency	Technology	Year 2000 Average lb/mmBtu	Emission Rate after Control lb/mmBtu	Removal Efficiency
Coleman Unit 1	DCS/NN/ Field Device	0.420	0.378	10.00%	OFA/DCS/NN/Field Devices	0.420	0.223	47.00%
Coleman Unit 2	DCS/NN/ Field Device	0.428	0.385	10.00%	OFA/DCS/NN/Field Devices	0.428	0.227	47.00%
Coleman Unit 3	DCS/NN/ Field Device	0.417	0.375	10.00%	OFA/DCS/NN/Field Devices	0.417	0.221	47.00%
HMPL Unit 1	SCR/BOP	0.457	0.046	90.00%	SCR	0.457	0.046	90.00%
HMPL Unit 2	SCR/BOP	0.478	0.048	90.00%	SCR	0.478	0.048	90.00%
Green Unit 1	SCR/DCS/ NN/BOP	0.412	0.041	90.00%	Coal Reburn/ DCS/NN/BOP	0.412	0.206	50.00%
Green Unit 2	SCR/DCS/ NN/BOP	0.422	0.042	90.00%	Coal Reburn/ DCS/NN/BOP	0.422	0.211	50.00%
Wilson Unit	SCR/DCS/ NN/BOP	0.431	0.043	90.00%	SCR/DCS/NN/BOP	0.431	0.043	90.00%
Reid Unit 1	50% Gas Fired	0.812	0.149	81.71%	50% Gas Fired	0.812	0.149	81.71%
Reid CT	Gas Fired	0.890	0.150	83.15%	Gas Fired	0.890	0.150	83.15%
Target NO$_x$	4,571	---	---	---	4,571	---	---	---
NO$_x$ Emissions, tons	4,488	---	---	---	4,534	---	---	---
Capital Cost, $1,000,000	170.5	---	---	---	143.6	---	---	---

WKE Sources of Data

The following sources of data were utilized by WKE in the development of the NO_x compliance plan.

1. S&L 1999 NO_x Compliance Study.
2. Power Technology 2001 evaluation of NO_x reduction technologies.
3. WKE study of alternate NO_x reduction technologies which included Rotating Over-fire Air (ROFA) and coal re-burn systems.
4. WKE evaluation of potential suppliers of neural network control systems.
5. WKE's Base Case plan 5 results which utilized baseline performance data from 1997, 2000 and the first quarter of 2001.

WKE Assumptions

WKE assumptions utilized in the development of Plan 8A were as follows:

1. Projected NO_x reductions included:
    - a. 90 percent from the Wilson unit resulting from the addition of SCR/DCS/NN/BOP.
    - b. 90 percent from the HMPL Units 1 and 2 resulting from the addition of SCR systems.
    - c. 47 percent from the Coleman units and 50 percent from the Green units with the installation of AOFA and coal re-burn system, respectively.
    - d. 81.71 percent from the Reid Unit 1 through the installation of a natural gas co-fired system.
    - e. 83.15 percent from the Reid CT through the installation of a natural gas fuel system.
    - f. Included in the control strategies is a conservative 10 percent improvement in NO_x emissions resulting from the installation of DCS and NN systems. This improvement was documented in Stanley Consultants Meeting Notes No. 2 dated April 18, 2001.
2. Capital costs were revised to reflect the latest contractor and/or vendor negotiations.
3. Annual catalyst costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study.

4. The first year fixed O&M costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study. These costs were adjusted for escalation at a rate of 3 percent per year.

5. The variable O&M costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study.

6. An adjusted ammonia cost of $350 per ton was utilized.

7. The OTAG season capacity factors utilized in the plan development were 90 percent for all BREC and HMPL Units 1 and 2, except the Reid Unit 1 and the Reid CT.

8. Contingency cost estimates which are typical of these types of analysis were eliminated from the compliance plan cost projections.

9. NO_x emission reductions from 14,000 tons to less than 4,600 tons were to occur during the OTAG season beginning in May 2004.

10. The use of SNCR technology was omitted from the compliance strategies. The SNCR technology was an option which could be implemented in the event the developing technologies proved to be inadequate.

11. The WKE models assumed a purchase price of $2,500 per ton for NO_x emission allowances to compensate for excess emissions.

12. WKE Plan 8A assumed 100 percent availability of the units during the OTAG season.

13. Data presented in the WKE Plan 8A spreadsheet indicates "through 2000 CEM heat rates" were used.

14. Baseline Performance Tests were performed by Babcock Borsig Power during the year 2000 on the Green units and the Wilson unit. These tests provided data which was utilized in the sizing calculation for the future SCRs and selection of the proper catalyst type. *The SCR baseline testing utilized coal as the fuel for the Green units.* The SCR baseline testing utilized the following fuel blends for the tests performed on the Wilson unit:

    - 75 Percent Pet Coke/25 Percent Bituminous Coal
    - 40 Percent Pet Coke/60 Percent Bituminous Coal
    - 0 Percent Pet Coke/100 Percent Bituminous Coal

15. Baseline Performance Tests were performed by Clean Air Engineering during the year 2002 on the HMPL Units 1 and 2. The testing was performed utilizing a fuel blend of:

    - 60 Percent Pet Coke/40 Percent Bituminous Coal
    - 80 Percent Pet Coke/20 Percent Bituminous Coal
    - 0 Percent Pet Coke/100 Percent Bituminous Coal

16. At the time of the S&L study the boiler baseline testing had not been performed.

Power Technology Review of WKE Compliance Plans

Power Gen was the parent company of WKE and Power Technology at the time the compliance plans were developed. Power Technology is an engineering subsidiary of Power Gen and is an English company similar to the EPRI organization in the United States. Power Technology evaluated the WKE NO_x reduction technologies and compliance Plan 8A. Power Technology commented on the compliance plan which was summarized in a spreadsheet dated July 20, 2001. At a meeting held on April 18, 2001, with BREC, HMPL, and Stanley Consultants representatives, WKE presented a summary slide entitled "Position Summary" which stated "Power Technology performed an evaluation of WKE's compliance plan and found the plan to be prudent and well engineered."

Power Technology Recommendations

WKE Plan 8A compliance strategies reviewed by Power Technology resulted in the following comments to WKE which were dated July 20, 2001:

1. Overall the compliance plan looks reasonable, given that the required NO_x reduction levels can be delivered by the combustion modifications (over fire air and coal re-burn technologies) proposed for Green and Coleman.

2. Target reductions in NO_x emissions appeared credible based on Power Technologies current knowledge, however, Power Technology recommended additional evaluations to determine the effect on the plan in the event any of the reduction strategies do not deliver the NO_x reductions anticipated.

3. Power Technology indicated the compliance plan is clearly very tight. This would be expected as there is little incentive for WKE to over comply. It was important to try to identify any other tactics which might give an increase in the margin to allow for unexpected contingencies while not reducing generation.

4. Comments regarding the individual plants included:

    a. *The Green units have high residence time which makes them well suited for the application of coal re-burn. The selected options of coal re-burn,* together with the DCS and neural network for continuous system optimization represents a viable and attractive option for the station.

   b. The application of over fire air accompanied by neural network and DCS to the Coleman units represents a viable option and is typical of the approach being adopted on numerous units of similar size and duty.

   c. The utilization of the high efficiency SCR on the Wilson unit represents a sound technical option. Power Technology noted the heat rate shown in the spreadsheet for Wilson appeared high (11,700 Btu/kWh). If the actual heat rate value is in the mid 10,000s Btu/kWh the results would be a significant increase in the margin of compliance. Power Technology recommended investigating the high heat rate noted for the Wilson Unit.

   d. The utilization of the high efficiency SCR on the HMPL Units 1 and 2 represents a sound technical option.

   e. Power Technology questioned the assumption the Reid Unit 1 would run on 50 percent gas throughout the year, given the high cost of gas. Also, Power Technology indicated this would impact the SO_2 compliance for the company. In addition, Power Technology stated if the cost of generation from the Reid Unit 1 is too high, this may also force the operation of the higher emitting NO_x units, which would erode the compliance margin. The question was also asked if the gas co-firing was likely to impact the load factor, which this plant has seen historically. Most likely this unit would only operate at times when the system price is high.

5. Power Technology noted the overall system spreadsheet appears to assume the loading of the units is essentially the same as the historical loading. There is a potential benefit in NO_x to be had if it is possible to bias the operation so that any SCR units operate in true base load mode, at or near 100 percent Maximum Continuous Rating (MCR) providing that they are available. This assumes that it is acceptable operationally and in terms of system scheduling.

6. Power Technologies noted the energy production projections for 2007 were utilized in the spreadsheet but it is not clear whether the projected load in the intervening years is greater than that level. If this is the case then there is clearly little or negative margin in those years.

Stanley Consultants Review of WKE Plan 8A

Stanley Consultants Sources of Data

The following sources of data were reviewed:

1. S&L 1999 NO_x Compliance Study

2. Stanley Consultants Inc. meeting notes and letters

3. BREC information

    a. Information for Plant Operations Review and NO_x Compliance

    b. Environmental Clear Skies Assumptions

    c. Additional Production Information

4. WKE NO_x Compliance Plan 5B and 8A spreadsheets

5. Third-Party Reports. Appendix A contains a complete listing of the reports reviewed.

6. Actual WKE performance results from the 2004 and 2005 OTAG seasons.

7. NBV and CWIP report review.

NBV & CWIP Report Review

Appendix B documents in a summary listing the WKE Plan 8A NO_x reduction technologies, the asset value, and the date of purchase of the asset as listed in the NBV and CWIP reports. The list documents the equipment installed. Table 2-5 documents the status of the expenditures associated with the implementation of WKE Plan 8A NO_x reduction technologies as of December 31, 2005, in the NBV and CWIP reports.

Table 2-5 WKE Plan 8A Comparison to NBV & CWIP Report

Unit	WKE Plan 8A Planned NO_x Reduction Technology	NBV/CWIP Report NO_x Reduction Technology Expenditures
Coleman Unit 1	OFA/DCS/NN	OFA/DCS
Coleman Unit 2	OFA/DCS/NN	OFA/DCS/NN
Coleman Unit 3	OFA/DCS/NN	OFA/DCS
HMPL Unit 1	SCR/DCS/NN	SCR/DCS
HMPL Unit 2	SCR/DCS/NN	SCR/DCS
Green Unit 1	Coal Re-burn/DCS/NN	Coal Re-burn/DCS/NN
Green Unit 2	Coal Re-burn/DCS/NN	Coal Re-burn/DCS/NN
Wilson Unit	SCR/DCS/NN	SCR/DCS
Reid Unit 1	50% Gas Co-Fired	Gas Burners
Reid CT	Gas Fired	Dual Fire Burners

Conclusions

The following conclusions result from the Stanley Consultants' review of the documents:

1. WKE Plan 8A includes the use of innovative technologies (NN, AOFA, and coal re-burn system), to achieve NO_x reductions. The uses of coal re-burn and AOFA systems affect the combustion within the boiler. Low NO_x operation as a result of the implementation of the coal re-burn and AOFA system in an existing boiler in combination with a coal supply containing a higher sulfur content will result in increases in Loss on Ignition (LOI), waterwall tube wastage, and an increase in carbon monoxide (CO) emissions and opacity. These conditions may also lead to a reduction in unit availability:

    a. By reducing the available oxygen in the lower furnace burner regions, a lower combustion temperature will occur. This staging of air or fuel will result in reduced levels of thermal NO_x formation. The result of this staged combustion can be an increase in LOI.

    b. The LOI which is a measurement of unburned carbon is a result of incomplete combustion of fuel which can result in a significant loss of boiler efficiency.

    c. An increase in LOI has a negative impact on precipitator performance. Due to carbon in the ash resulting from a higher LOI, an increase in the dust load and its resistivity to the flue gas cleaning system will increase the opacity.

    d. Waterwall tube wastage occurs due to altered flue gas flow patterns along furnace walls which contain low oxygen concentrations. Combine this reducing atmosphere with the minerals and sulfur content in the fuel and the results are acidic materials which chemically attack the carbon steel tube material. Obviously with higher concentrations of sulfur in the fuel the more aggressive this mechanism will be in the furnace volume.

    e. Higher CO emissions are also a result of incomplete combustion.

2. WKE chose to proceed with WKE Plan 8A. In a letter dated February 19, 2002 WKE agreed to hold BREC harmless for any additional capital or O&M costs that it would be liable for the installation of the technologies and scope of work as identified in WKE Plan 5B in order to comply with the Kentucky SIP regulation compliance strategy. The limits identified in WKE Plan 5B were budget costs, but as stated in the February 19, 2002 letter, the limit protections were extended by WKE to include actual costs.

3. The upgrade of plant control systems to DCS and NN systems will result in additional NO_x control and other advantages will result. However, the control system, analyzers and instruments must be maintained and periodically calibrated. If not, the advantages of the sophisticated digital control and NN will be lost. Upon review of the WKE reported NO_x emission rates, the systems may not be optimally tuned.

4. Contingency cost estimates were eliminated from WKE's compliance plan cost projections. Stanley Consultants typically adds 10 percent for contingencies.

5. The impact of unit starts on NO_x allowance consumption was not included in the Power Technology review, S&L Report nor considered by WKE.

6. All units are assumed to be 100 percent available during the OTAG season. This availability was an incorrect assumption, as evidenced by forced outage causes and planned outage events and the additional NO_x emissions which are a result of these events. Forced outages and planned outages are documented in Appendix C and D. Annual Forced Outage Rates (FORs) by unit are summarized in Table 2-6 for the period 1998 through 2002.

Table 2-6 1998-2002 Annual FORs (%)

Unit	1998	1999	2000	2001	2002
Coleman Unit 1	2.7	0.0	0.0	0.0	2.7
Coleman Unit 2	2.5	1.4	5.9	0.5	1.0
Coleman Unit 3	0.3	0.8	2.3	1.8	5.9
HMPL Unit 1	2.7	3.8	2.5	2.6	5.7
HMPL Unit 2	2.1	2.5	3.9	7.4	8.8
Green Unit 1	0.1	0.7	4.1	1.6	3.5
Green Unit 2	0.5	0.7	4.4	0.2	0.7
Wilson Unit	1.2	2.6	2.7	0.7	6.6
Reid Unit 1	6.7	2.0	3.1	7.4	6.7

7. The HMPL and Wilson units would utilize SCR/DCS/NN/BOP to achieve 90 percent NO_x reduction in the WKE Plan 8A. This information was obtained from the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001. The WKE Plan 8A spreadsheet notes that the HMPL Units 1 and 2 would utilize SCR systems to achieve 90 percent NO_x reduction. The noted differences could result in a flaw in the WKE Plan 8A. The WKE Plan 8A spreadsheet notes that the Wilson unit would utilize SCR/DCS/NN/BOP to achieve 90 percent NO_x reduction and does not vary from the information presented in the April 18, 2001 meeting.

8. The HMPL and Wilson units would utilize SCR/DCS/NN/BOP upgrades to achieve 90 percent NO_x reduction in the WKE Plan 5B. This information was obtained from the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001. The WKE Plan 5B spreadsheet notes that the HMPL Units 1 and 2 would utilize SCR/BOP to achieve 90 percent NO_x reduction. The noted differences could result in a flaw in the WKE Plan 8A. The WKE Plan 5B spreadsheet notes that the Wilson unit would utilize SCR/DCS/NN/BOP to achieve 90 percent NO_x reduction and does not vary from the information presented in the April 18, 2001 meeting.

9. The S&L report documents the following:

> *Use of high sulfur coal with SCR also creates concern over ABS (ammonium bisulfate) deposition but goes further in that it can create corrosion problems, "blue plume" opacity problems, and can potentially lead to accelerated deactivation of the SCR catalyst.*

This issue would also result in the lack of availability of the units which were retrofitted with SCR units, due to the corrosion in the air heaters and associated ductwork or due to air heaters plugging from sulfuric acid and calcium sulfate attack. As a result, overall unit availability will have an effect on the NO_x compliance.

10. Upon review of the WKE NBV and CWIP report, Stanley Consultants concludes that not all of the neural network systems have been installed. Refer to Table 2-5.

11. A comparison of the recommendations by S&L and the WKE Plan 8A is shown in Table 2-7.

Table 2-7 Comparison of Implementation Strategies

Unit	S&L Alternative Case (1)	WKE Plan 8A
Coleman Unit 1	SNCR	OFA/DCS/NN
Coleman Unit 2	SNCR	OFA/DCS/NN
Coleman Unit 3	SNCR	OFA/DCS/NN
HMPL Unit 1	SCR	SCR
HMPL Unit 2	SCR	SCR
Green Unit 1	SCR	Coal Re-burn/DCS/NN
Green Unit 2	SCR	Coal Re-burn/DCS/NN
Wilson Unit	SCR	SCR/DCS/NN
Reid Unit 1	SNCR	50% Gas Co-Fired
Reid CT		Gas Fired
Target NO_x, tons	4,334	4,571
NO_x Emissions, tons	4,459	4,534
Excess NO_x Allowances, tons	125	37
Capital Cost, $1,000,000	180	143.6

Notes:

(1) *An Alternative case, which also considers a 5 percent margin* below the Kentucky SIP call, was developed to aid in the evaluation of not installing a SCR at Coleman Unit 3 and retrofitting SNCRs at all Coleman units. The NO_x allowances generated will be approximately 125 tons lower than required to comply with the Kentucky SIP regulations of 4334 tons.

DCS – Distributed Control System
NN – Neural Network
OFA – Over-fired Air

Section 3

Existing WKE Plan 8A Performance Review

Introduction

Stanley Consultants reviewed the performance of WKE Plan 8A for the 2004 and 2005 OTAG seasons. Information provided to BREC and Stanley Consultants at the January 5, 2006, NO_x Compliance Review Meeting was utilized in the review. A comparison of the Plan's performance and an analysis of the actual performance conditions versus the WKE Plan 8A assumptions are provided below.

2004 and 2005 OTAG Season Evaluation

2004 And 2005 NO_x Actual Emissions Compared to WKE's Operating Budgets

WKE provided actual generation and NO_x emissions for the OTAG season of 2004 and 2005 as shown in Table 3-1 and 3-2. Appendix G contains the information provided by WKE. These values were then compared to the WKE anticipated budgets for the respective years and the differences are noted.

Table 3-1 2004 OTAG Season
NO_x Actual Emissions Compared to WKE Operating Budget

Unit	Budget		Actual		Difference from Budget		
	Energy Production (MWh)	Tons NO_x	Energy Production (MWh)	Tons NO_x (1)	Energy Production (MWh)	Tons NO_x	% Over Budget
Coleman Unit 1	393,866	407	400,781	515	6,915	108	21
Coleman Unit 2	382,636	407	449,642	544	67,006	137	25
Coleman Unit 3	372,632	452	402,259	539	29,627	87	16
HMPL Unit 1	358,982	103	449,570	199	90,588	96	48
HMPL Unit 2	347,080	102	498,862	214	151,782	112	52
Green Unit 1	780,686	672	798,406	649	17,720	(23)	(4)
Green Unit 2	768,926	660	783,380	683	14,454	23	3
Wilson Unit	1,534,741	321	1,446,861	421	(87,880)	100	24
Reid Unit 1	29,060	3	39,521	45	10,461	42	93
Reid CT	0	0	5,040	47	5,040	47	100
Total	4,968,609	3,127	5,274,322	3,853	305,713	726	23

Notes:
(1) Actual 2004 NO_x season allotment is 4500 tons.

Table 3-2 2005 OTAG Season
NO_x Actual Emissions Compared to WKE Operating Budget

Unit	Budget		Actual		Difference from Budget		
	Energy Production (MWh)	Tons NO_x	Energy Production (MWh)	Tons NO_x (1)	Energy Production (MWh)	Tons NO_x	% Over Budget
Coleman Unit 1	347,566	532	439,878	737	92,312	205	28
Coleman Unit 2	328,271	506	405,860	636	77,589	130	20
Coleman Unit 3	448,993	676	449,803	757	810	81	11
HMPL Unit 1	513,992	134	543,847	213	29,855	79	37
HMPL Unit 2	496,904	127	511,406	204	14,502	77	37
Green Unit 1	815,073	887	864,259	888	49,186	1	1
Green Unit 2	771,864	849	802,116	882	30,252	33	4
Wilson Unit	1,593,484	414	1,507,306	424	(86,178)	10	2
Reid Unit 1	85,773	242	130,256	433	44,483	191	(5)
Reid CT	0	0	1,831	23	1,831	23	100
Total	5,401,920	4,367	5,656,561	5,195	254,641	828	19

Notes:
(1) Actual 2005 NO_x season allotment is 4500 tons.

WKE Plan 8A Model Parameters

WKE Plan 8A spreadsheet description and parameters are as follows. Appendix E contains a copy of the WKE Plan 8A spreadsheet.

1. OTAG season energy production in kilowatt hours (kWh) is a calculated value developed from the product of gross capacity generation in kilowatts (kW) times the average capacity factor times the OTAG season hours.

2. Continuous emission monitor (CEM) heat rates expressed in Btu/kWh for the calendar year 2000 were utilized in WKE Plan 8A.

3. WKE assumed 100 percent availability for all units in Plan 8A. A 90 percent capacity factor was utilized for the Coleman units, HMPL units, Green units, and the Wilson Unit. An 85 percent capacity factor was assumed for Reid Unit 1 and the Reid CT.

4. WKE utilized the average emission rates expressed in lbs/mmBtu for the calendar year 2000 for each unit in WKE Plan 8A.

5. Projected NO_x reductions are documented in Section 2, Table 2-3. The WKE Plan 8A included the switch of the Reid Unit 1 to co-firing natural gas with coal. The expected NO_x reduction for Reid Unit 1 was from 0.8 to 0.85 lbs/mmBtu (0 percent removal efficiency) for the coal fuel only case to 0.15 lbs/mmBtu (81.71 percent removal efficiency) when firing natural gas. Gas burners were installed on the Reid Unit 1, however they are not utilized due to the high price of natural gas. WKE installed a flue gas recirculation (FGR) system for Reid Unit 1 as an additional NO_x reduction technology. Cooling air thru the gas burners is similar to an overfire air system and in conjunction with the FGR has resulted in a NO_x reduction to 0.41 lbs/mmBtu (49.51 percent removal efficiency) without the use of natural gas.

6. The OTAG season has 3672 hours of operation and this number was utilized in the spreadsheet calculations.

2004 and 2005 OTAG Season Model Evaluation Parameters

The WKE Plan 8A spreadsheet was utilized in calculating the variations from the original plan assumptions and in the evaluation of the 2004 and 2005 OTAG season performance. Parameters used in the evaluation of the 2004 and 2005 OTAG season performance are documented in Tables 3-1 "2004 OTAG Season NO_x Actual Emissions Compared to WKE Operating Budget," 3-2 "2005 OTAG Season NO_x Actual Emissions Compared to WKE Operating Budget," 3-3 "Emission Rates (lbs/mmBtu)", 3-4 "Gross Capacity Factors – OTAG Season," 3-5 "Heat Rates," and 3-6 "2004 & 2005 OTAG Season Available Hours," These parameters were utilized in the WKE Plan 8A spreadsheet to generate the 2004 OTAG Season Plan 8A NO_x Tons presented in Table 3-9 and the 2005 OTAG Season Plan 8A NO_x Tons presented in Table 3-10.

1. The 2004 and 2005 actual gross energy production documented above in Tables 3-1 and 3-2 for the OTAG season (adjusted for the 2004 OTAG season beginning May 31) was utilized as data inputs in 2004 and 2005 OTAG Season WKE Plan 8A models.

2. Actual emission rates by unit were utilized in the 2004 and 2005 OTAG season evaluation. Table 3-3 depicts the comparison of WKE Plan 8A assumed emission rates to the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.

Table 3-3 Emission Rates (lbs/mmBtu)

Unit	WKE Plan 8A Assumed Emission Rates	Actual 2004 Emission Rates(1)	Actual 2005 Emission Rates(1)
Coleman Unit 1	0.223	0.293	0.306
Coleman Unit 2	0.227	0.284	0.296
Coleman Unit 3	0.221	0.289	0.299
HMPL Unit 1	0.046	0.051(2)	0.056(2)
HMPL Unit 2	0.048	0.038(2)	0.055(2)
Green Unit 1	0.206	0.203	0.205
Green Unit 2	0.211	0.198	0.209
Wilson Unit	0.043	0.043(2)	0.037(2)
Reid Unit 1	0.149	0.260	0.403
Reid CT(3)	0.150	0.150	0.150

Notes:
(1) Provided by WKE in the "04 05 Ozone Season Emission Rates.xls" spreadsheet. The average of the months of the OTAG season were used.
(2) The emission rates used for HMPL Units 1 and 2 and Wilson Unit are exclusive of SCR events.
(3) Actual 2004 and 2005 emission rate data is not available. The emission rate documented in WKE Plan 8A was utilized.

3. WKE actual 2004 and 2005 gross capacity factors were used in 2004 and 2005 OTAG Season WKE Plan 8A models as documented in Table 3-4.

4. WKE actual 2004 and 2005 gross heat rates were used in 2004 and 2005 OTAG Season WKE Plan 8A models as documented in Table 3-5.

5. Stanley Consultants determined the number of forced outage hours and planned outage hours during the 2004 and 2005 OTAG seasons from the 2004 and 2005 production outage reports. The OTAG season for 2004 consisted of the hours beginning on May 31 and ending on September 30. For 2005, the OTAG season began May 1 and ended on September 30. The number of hours of availability for each unit is documented in Table 3-6.

Generation Impacts to WKE Plan 8A Assumptions

WKE Plan 8A Excel spreadsheet was utilized in calculating variations from the original plan assumptions in the review of the actual performance of the WKE Plan 8A for the 2004 and 2005 OTAG seasons. Data input to the spreadsheet was obtained from several sources to determine the impact of the historical data on the WKE Plan 8A performance.

Capacity Factors

Capacity factors utilized for each unit were calculated utilizing the actual WKE OTAG season gross energy production in megawatt hours (MWh), the gross capacity, and the hours of operation. Table 3-4 documents a comparison between capacity factors calculated from actual gross energy production in MWhs and the original capacity factors assumed in the WKE Plan 8A.

Table 3-4 Gross Capacity Factors – OTAG Season

Unit	Assumed WKE Plan 8A	Calculated from 2004 Actual Gross Energy Produced(1)	Calculated from 2005 Actual Gross Energy Produced(2)
Coleman Unit 1	90.0%	76.4%	79.2%
Coleman Unit 2	90.0%	79.9%	73.2%
Coleman Unit 3	90.0%	75.8%	76.1%
HMPL Unit 1	90.0%	89.9%	94.6%
HMPL Unit 2	90.0%	86.1%	88.6%
Green Unit 1	90.0%	95.2%	100.0%
Green Unit 2	90.0%	96.7%	98.6%
Wilson Unit	90.0%	94.8%	98.3%
Reid Unit 1	85.0%	55.8%	78.8%
Reid CT	85.0%	33.4%	30.7%

Notes:
(1) Calculated from Actual 2004 OTAG season gross energy produced kWh (adjusted for OTAG season beginning May 31) divided by the gross capacity of the unit divided by the hours in operation.
(2) Calculated from Actual 2005 OTAG season gross energy produced kWh divided by the gross capacity of the unit divided by the hours in operation.

Heat Rate Impacts

Actual gross heat rates were used in the 2004 and 2005 OTAG season evaluation. Table 3-5 compares the gross 2004 and 2005 heat rates and the original heat rates utilized in the WKE Plan 8A spreadsheet.

Table 3-5 Heat Rates

Unit	Assumed WKE Plan 8A [(1)]	2004 Heat Rates[(2)]	2005 Heat Rates[(2)]
Coleman Unit 1	10,158	9,979	9,771
Coleman Unit 2	10,837	10,146	10,145
Coleman Unit 3	10,552	9,704	9,599
HMPL Unit 1	10,636	9,713	9,832
HMPL Unit 2	10,907	9,982	10,153
Green Unit 1	10,096	10,018	10,203
Green Unit 2	10,591	10,181	10,259
Wilson Unit	11,918	10,539	10,330
Reid Unit 1	11,212	11,540	11,354
Reid CT[(3)]	10,585	10,585	10,585

Notes:

(1) The "Assumed WKE Plan 8A" heat rates were noted as "thru 2000 CEM heat rates". The heat rates were assumed to have been determined from CEM data.

(2) Actual 2004 and 2005 gross heat rates used for all units are derived from coal feeder and coal analysis data collected by WKE, with the exception of the Reid CT.

(3) Actual heat rate information is not available. The heat rate documented in WKE Plan 8A was utilized.

Unit Availability Impacts

Actual unit availability during the 2004 OTAG season and the 2005 OTAG season was determined for each unit through a review of the 2004 and 2005 production outage reports. Both forced outage hours and planned outage hours were determined and documented in a spreadsheet by unit to determine the impact(s). Specific forced outage and planned outage events by unit for the 2004 OTAG season and the 2005 OTAG season were identified and documented in Appendix C. Table 3-6 documents a summary of these events for the 2004 and 2005 OTAG seasons. The WKE Plan 8A assumed no outages during the OTAG season.

Table 3-6 2004 & 2005 OTAG Season Available Hours

Unit	2004 Forced Outage Hours	2004 Planned Outage Hours	2004 OTAG Season Available Hours[(1)]	2004 Percent Available	2005 Forced Outage Hours	2005 Planned Outage Hours	2005 OTAG Season Available Hours[(2)]	2005 Percent Available
Coleman Unit 1	151.31	132.08	2,668.61	90.4%	180.98	0.00	3,491.02	95.1%
Coleman Unit 2	138.28	0.00	2,813.72	95.3%	184.88	0.00	3,487.12	95.0%
Coleman Unit 3	82.88	0.00	2,869.12	97.2%	104.25	0.00	3,567.75	97.2%
HMPL Unit 1	655.73	0.00	2,296.27	77.8%	186.30	0.00	3,485.70	94.9%
HMPL Unit 2	29.15	0.00	2,922.85	99.0%	53.45	181.48	3,437.07	93.6%
Green Unit 1	197.25	0.00	2,754.75	93.3%	67.18	26.00	3,578.81	97.5%
Green Unit 2	50.30	0.00	2,901.70	98.3%	45.03	120.67	3,506.30	95.5%
Wilson Unit	259.94	0.00	2,692.06	91.2%	250.80	0.00	3,421.20	93.2%
Reid Unit 1	3.48	2,511.05	437.47	14.8%	372.52	794.88	2,504.60	68.2%
Reid CT	0.00	2,783.00	169.00	5.7%	0.00	3,582.00	90.00	2.5%

Notes:
(1) Total 2004 OTAG season hours of 2,952 less forced outage and planned outage hours.
(2) Total 2005 OTAG season hours of 3,672 less forced outage and planned outage hours.

Unit Starts

The actual number of starts by unit for the 2004 and 2005 OTAG seasons is documented in Table 3-7. The WKE Plan 8A assumes no unit starts during the OTAG season. The 2004 and 2005 OTAG Season evaluation models assume no unit starts during the OTAG season.

Table 3-7

Number of Unit Starts During the OTAG Seasons

Unit	2004 Number of Unit Starts	2005 Number of Unit Starts
Coleman Unit 1	5	4
Coleman Unit 2	3	4
Coleman Unit 3	5	4
HMPL Unit 1	4	4
HMPL Unit 2	1	2
Green Unit 1	6	3
Green Unit 2	3	7
Wilson Unit	6	9
Reid Unit 1	11	9

During the NO_x Compliance Plan Review meeting of January 5, 2006, WKE noted that they had not anticipated in the WKE Plan 8A the number of unit starts experienced during the 2004 or 2005 OTAG seasons. These starts resulted in a number of NO_x allowances consumed during those unit starts.

Additional NO_x emissions were generated due to SCR warm up after outages that occurred on the Wilson Unit and HMPL Units 1 and 2. During the warm up of either HMPL Unit 1 or 2, the gas stream is bypassing the SCR and the Flue Gas Desulfurization (FGD) systems. The bypass stack is not equipped with a NO_x analyzer and thus the NO_x emissions are reported as the maximum potential to emit during the period of bypass.

Table 3-8 documents the number of NO_x allowances consumed per unit start in 2004 and 2005 for the Wilson Unit and HMPL Units 1 and 2. WKE Plan 8A assumed no unit starts and thus no NO_x allowances would be consumed during the OTAG seasons.

Table 3-8 Additional NO_x Allowances Consumed by SCR Units

Unit	2004 Number of Unit Starts	2004 Additional NO_x Allowances Consumed$^{(1)}$	2005 Number of Unit Starts	2005 Additional NO_x Allowances Consumed$^{(2)}$
HMPL Unit 1	4	14.36	4	18.56
HMPL Unit 2	1	2.05	2	12.98
Wilson Unit	6	73.88	9	82.17
Total	--	90.29	--	113.71

Notes:

(1) As documented in the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls" the average additional NO_x emissions per SCR warm up event are: (H1 3.59 tons per event), (H2 2.05 tons per event), and (W1 12.313 tons per event). These averages were multiplied by the number of unit starts to determine the number of additional allowances consumed.

(2) As documented in the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls" the average additional NO_x emissions per SCR warm up event are: (H1 4.64 tons per event), (H2 6.49 tons per event), and (W1 9.13 tons per event). These averages were multiplied by the number of unit starts to determine the number of additional allowances consumed.

WKE provided a spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" in the January 5, 2006, WKE NO_x Compliance Review meeting. This spreadsheet documented events during which additional tons of NO_x emissions were generated during the 2004 and 2005 OTAG seasons.

Based on the data presented, the WKE Plan 8A does not allow for sufficient variations for equipment failure events, forced outage events, or additional generation. These events and the resultant NO_x emissions are documented in Tables 3-9 and 3-10. Appendix D *identifies the events and the additional amount* of NO_x emissions determined as a result of:

- HMPL Units 1 and 2 SCR system non-compliance period emissions. These periods of time are required by EPA to be reported at the maximum potential NO_x emissions rate resulting from periods when the generating units are operated with the SCR in the bypass mode.
- Operation of the HMPL Units 1 and 2 SCR system in the bypass mode due to the application of coal drying agents and allowing for repairs and tuning of the HMPL Units 1 and 2 SCR systems.
- Additional emissions known to occur through operational variances. For example the operation of Wilson Unit Pulverizer No. 3 and burner combination. This pulverizer and burner combination feeds fuel to the upper level of burner elevation and the resultant "Burn out" time is much less thus contributing to thermal NO_x formation.

- Additional emissions due to variations in CEM heat input data.
- Additional emissions due to the difference in actual versus planned unit heat rate values.

Results

The following results were developed from the 2004 OTAG Season evaluation versus the WKE Plan 8A assumptions:

1. Table 3-9 compares the 2004 WKE reported NO_x emissions, the 2004 OTAG Season Plan 8A modeled NO_x emissions, the WKE additional tons of NO_x due to extraordinary events (2004 OTAG Additional NO_x Events), and the WKE Plan 8A NO_x emissions.

    a. The difference noted in the "WKE Reported 2004 NO_x Tons" column of 644 Excess NO_x Allowances and the "2004 Total NO_x Tons" column of 414.3 Excess NO_x Allowances from the 2004 OTAG Season Evaluation are attributed to differences in heat rate and emission rates. A discussion of each of these parameters follows:

        (1) The 2004 OTAG Season Evaluation Plan 8A Spreadsheet used WKE Annual Gross Heat Rates. The WKE Plan 8A spreadsheet utilized 2000 CEM Heat Rates. Unit heat rates have an impact on the calculated NO_x emissions.

        (2) The 2004 OTAG Season Evaluation Plan 8A spreadsheet used actual emission rates versus the WKE Plan 8A assumed emission rates. Removal efficiencies based on the actual emission rates are less for the following units, thus contributing to the failure of WKE Plan 8A to perform as projected:

            (a) Coleman Units 1, 2, and 3 - WKE Plan 8A removal efficiency was 47 percent. Actual emission rates indicate the removal efficiencies are currently 30.24, 33.70, and 30.64 percent, respectively. Coleman units NO_x reduction technologies included the use of innovative technology (AOFA). This technology was chosen by WKE with a limited number of trial installations and test data available. The actual emissions rates indicate the AOFA system is not performing as anticipated.

            (b) HMPL Unit 1 – The WKE Plan 8A removal efficiency was projected to be 90 percent. Actual emission rates indicate the removal efficiency is 88.87 percent. The continuing startup activities and other contractual issues have prevented final tuning of the SCR systems.

(c) Reid Unit 1 – The strategy of fuel switching (from coal to natural gas) was projected to result in a NO_x emissions removal efficiency of 81.71 percent. Current removal efficiency using the FGR system and the installation of natural gas burners on the top burner elevation and utilizing the cooling air as over fired air results in a removal efficiency of 68.01 percent.

Table 3-9 2004 OTAG Season Evaluation - WKE Plan 8A

		2004 OTAG Season Evaluation			
Unit	**WKE Reported 2004 NO_x Tons(1)**	**2004 OTAG Season Plan 8A NO_x Tons(2)**	**2004 WKE Additional NO_x Events Tons(3)**	**2004 Total NO_x Tons(4)**	**Projected WKE Plan 8A NO_x Tons(5)**
Coleman Unit 1	515	474.3	30.0	504.3	594
Coleman Unit 2	544	514.9	30.4	545.3	638
Coleman Unit 3	539	505.2	0.7	505.9	628
HMPL Unit 1	199	84.2	80.6	164.8	132
HMPL Unit 2	214	79.4	386.7	466.1	145
Green Unit 1	649	638.5	12.4	650.9	825
Green Unit 2	683	654.6	45.8	700.4	857
Wilson Unit	421	257.0	263.5	520.5	380
Reid Unit 1	45	24.2	0.4	24.6	171
Reid CT	47	2.9	---	2.9	164
Total	3,856	3235.2	850.5	4,085.7	4,534
Excess NO_x Allowances (Tons)	644	1,264.8	---	414.3	37
Additional NO_x Allowances Needed (Tons)	---	---	---	---	---
Allocated NO_x Allowances	4,500	4,500	---	4,500	4,571

Notes:

(1) Values were provided in the WKE spreadsheet entitled "2004 NO_x Actual Compared to Budget" Refer to Appendix G.

(2) Values were calculated in the 2004 OTAG Season Evaluation using 2004 information presented in Tables 3-1 through 3-6.

(3) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were taken from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls."

(4) This is a calculated value from the sum of "2004 OTAG Season Plan 8A NO_x Tons" column and "2004 WKE Additional NO_x Events Tons" column.

(5) Values were provided in the WKE Plan 8A Spreadsheet. Refer to Appendix E.

b. WKE provided information regarding additional tons of NO_x emissions due to other events to BREC in a meeting held on January 5, 2006. A detailed breakdown of these events and the additional tons of NO_x per event are included in Appendix D. A discussion of the events follows:

   (1) WKE reported in a spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" the additional NO_x emissions of 61.56 tons for "SCR warm up period" due to startup activities which occurred after a forced outage event at the Wilson Unit during the 2004 OTAG season. WKE's spreadsheet indicated the Wilson Unit SCR was off-line for 85 hours due to warm up activities after the outage events.

   (2) In 2004, WKE reported that the Wilson Unit Pulverizer No. 3 operated 1,209 hours. WKE provided an emission rate of 0.127193 tons of NO_x per hour resulting from the operation of the Pulverizer No. 3 during the OTAG season. The additional operation of the Pulverizer No. 3 resulted in 154 tons of additional NO_x emissions that had not been anticipated in the WKE Plan 8A.

2. The 2004 gross capacity factors were calculated using 2004 gross energy production. Green Units 1 and 2 and Wilson Unit gross capacity factors were higher than WKE Plan 8A capacity factors. The 2004 System Gross Capacity Factor average was 78.4 percent compared to WKE Plan 8A System Gross Capacity Factor average of 89 percent. The specific unit capacity factors will create additional NO_x emissions for those units not equipped with SCRs, when those factors are higher than the original plan or budget.

3. The actual 2004 gross heat rates resulted in lower values as compared to those utilized in the WKE Plan 8A except for Reid Unit 1.

4. WKE Plan 8A projected a 3,672 hour OTAG season and assumed 100 percent availability for all the units. The 2004 OTAG season of May 31 through September 30 was only 2,952 hours, which contributed to the excess allowances reported by WKE. Review of the production outage reports indicates that Coleman Unit 1 and Reid Unit 1 were off-line for planned outages (PO) for a period of time during the 2004 OTAG season. All units were off-line at one time or another due to forced outages during the 2004 OTAG season.

5. HMPL Unit 1 experienced a low water boiler event in August, 2004, which forced the unit off-line for approximately 515 hours during the months of August and September, 2004. This event increased energy production from non-SCR units during the August, 2004, time period resulting in higher than planned NO_x emissions for the system.

6. The HMPL Unit 2 SCR system is not operating to the availability guarantees provided in the contract. The continuing startup activities and other contractual issues have prevented final tuning of the SCR system. Thus optimum NO_x reduction performance has not been achieved.

7. Coleman units NO_x reduction technologies included the use of innovative technology (AOFA). This technology was chosen by WKE with a limited number of trial installations and test data available. Coleman Units 1, 2 and 3 AOFA systems are not performing as planned. As documented in the December 10, 2004 WKE/BREC Operating Committee Meeting, WKE had forecast the installation of an SNCR system on Coleman Unit 1, in accordance with a contract settlement requirement with Mobotech USA. This agreement indicates WKE had knowledge of a performance issue with the AOFA system.

The following results were derived from the 2005 OTAG season evaluation.

1. Table 3-10 compares the 2005 WKE reported NO_x emissions, the 2005 OTAG Season Plan 8A modeled NO_x emissions, the WKE additional tons of NO_x due to extraordinary events (2005 OTAG Additional NO_x Events), and the WKE Plan 8A NO_x emissions.

    a. The difference noted in the "WKE Reported 2005 NO_x Tons" column of 695 Additional NO_x Allowances Needed and the "2005 Total NO_x Tons" column of 528.4 Additional NO_x Allowances Needed from the 2005 OTAG Season Evaluation are attributed to differences in heat rate and emission rates. A discussion of each of these parameters follows:

        (1) The 2005 OTAG Season Evaluation Plan 8A Spreadsheet used WKE Annual Gross Heat Rates. The WKE Plan 8A spreadsheet utilized 2000 CEM Heat Rates. Actual unit heat rates have an impact on the tons calculated.

            (a) The 2005 OTAG Season Evaluation Plan 8A spreadsheet used actual emission rates versus the WKE Plan 8A assumed emission rates. Removal efficiencies based on the actual emission rates are less for the following units, thus the WKE Plan 8A did not perform as projected:

                1) Reid Unit 1 - Switching from coal to natural gas was projected to result in a removal efficiency of 81.71 percent. Current removal efficiency using the FGR system and the installation of natural gas burners on the top burner elevation and utilizing the cooling air as overfired air results in a removal efficiency of 50.37 percent.

Table 3-10 2005 OTAG Season Evaluation - WKE Plan 8A

		2005 OTAG Season Evaluation			
Unit	**WKE Reported 2005 NO_x Tons (1)**	**2005 OTAG Season Plan 8A NO_x Tons (2)**	**2005 WKE Additional NO_x Events Tons (3)**	**2005 Total NO_x Tons (4)**	**Projected WKE Plan 8A NO_x Tons (5)**
Coleman Unit 1	737	658.5	38.8	697.3	594
Coleman Unit 2	636	609.8	5.5	615.3	638
Coleman Unit 3	757	646.4	83.8	730.2	628
HMPL Unit 1	213	148.9	53.2	202.1	132
HMPL Unit 2	204	143.6	65.9	209.5	145
Green Unit 1	888	904.7	(1.5)	903.2	825
Green Unit 2	882	859.1	37.5	896.6	857
Wilson Unit	424	287.1	130.3	417.4	380
Reid Unit 1	433	298.0	57.4	355.4	171
Reid CT	23	1.5	---	1.5	164
Total	5,195	4,557.6	470.9	5,028.5	4,534
Excess NO_x Allowances (Tons)	---	---	---	---	37
Additional NO_x Allowances Needed (Tons)	695	57.6	---	528.5	---
Allocated NO_x Allowances	4,500	4,500	---	4,500	4,571

Notes:

(1) Values were provided in the WKE spreadsheet entitled "2005 NO_x Actual Compared to Budget" Refer to Appendix G.

(2) Values were calculated in the 2005 OTAG Season Evaluation using 2005 information presented in Tables3-1 through 3-6.

(3) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were taken from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls."

(4) This column is a calculated value from the sum of "2005 OTAG Season Plan 8A NO_x Tons" column and "2005 WKE Additional NO_x Events Tons" column.

(5) Values were provided in the WKE Plan 8A Spreadsheet. Refer to Appendix E.

2) Coleman Units 1, 2, and 3 – The WKE Plan 8A removal efficiency was 47 percent. Actual emission rates indicate the removal efficiencies are currently 27.05, 30.79, and 28.20 percent, respectively. Coleman units NO_x reduction technologies included the use of innovative technology (AOFA). This technology was chosen by WKE with a limited number of trial installations and test data available.

3) HMPL Units 1 and 2 – The WKE Plan 8A removal efficiency was projected to be 90 percent. Actual emission rates indicate the removal efficiencies are 87.81 percent and 88.42 percent, respectively. The continuing startup activities and other contractual issues have prevented final tuning of these SCR systems.

b. WKE provided information regarding additional tons of NO_x emissions due to other events to BREC in a meeting held on January 5, 2006. A detailed breakdown of these events and the additional tons of NO_x per event are documented in Appendix D. A discussion of these events follows:

   (1) WKE reported in a spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" the additional NO_x emissions of 82.14 tons for "SCR warm up period" due to startup activities after forced outages which occurred at the Wilson Unit during the 2005 OTAG season. WKE's spreadsheet indicated the Wilson Unit SCR was off-line for 113 hours due to warm up activities after outage events.

   (2) In 2005, the additional operation of the Wilson Unit Pulverizer No. 3 resulted in 30.51 tons of additional NO_x emissions that had not been anticipated in the WKE Plan 8A.

2. The 2005 gross capacity factors were calculated utilizing 2005 gross energy production. Green Units 1 and 2, HMPL Unit 1 and Wilson Unit gross capacity factors were higher than WKE Plan 8A capacity factors. The 2005 System Gross Capacity Factor average was 87.5 percent compared to WKE Plan 8A System Gross Capacity Factor average of 89 percent. The specific unit capacity factors will create additional NO_x emissions for those units not equipped with SCRs, when those factors are higher than the original plan or budget.

3. The actual 2005 gross heat rates resulted in lower values as compared to those utilized in the WKE Plan 8A except for Green Unit 1 and Reid Unit 1.

4. WKE Plan 8A assumes 100 percent availability for all the units. Review of the production outage reports indicates that Green Units 1 and 2, HMPL Unit 2 and Reid Unit 1 were off-line for planned outages (PO) or deferred maintenance (U04) for a period of time during the 2005 OTAG season. All units were off-line at one time or another due to forced outages during the 2005 OTAG season.

5. The HMPL Units 1 and 2 and the Wilson Unit were off-line due to forced outages or planned outages for a total of 672 hours during the 2005 OTAG season, or approximately 18 percent of the OTAG season period. These units have the higher NO_x removal efficiencies, thus during the 2005 OTAG season there was a large reliance on other generating units with less capable NO_x removal equipment.

6. The HMPL Units 1 and 2 SCR systems are not operating to the availability guarantees provided in the contract specification. The continuing startup activities and other contractual issues have prevented final tuning of these SCR systems. Thus optimum NO_x reduction performance has not been achieved.

Conclusions

WKE Plan 8A failed to perform as predicted based on several observations. The observed and documented deficiencies result from the following:

1. Differences in specific unit heat rates. WKE Plan 8A is sensitive to heat rate impacts with higher heat rates resulting in higher NO_x emissions. The heat rates utilized to develop the plan were higher than the actual heat rates for all the units except Reid Unit 1 and the 2005 Green Unit 1. These actual heat rate values would result in a lower NO_x emission for the OTAG season.

2. Differences in specific unit emission rates. WKE Plan 8A is sensitive to emission rate with higher emission rates resulting in higher NO_x emissions. The emission rates utilized to develop the plan were lower than the actual emission rates for Coleman Units 1, 2, and 3, HMPL Unit 1, and Reid Unit 1 in both 2004 and 2005. The HMPL Unit 2 actual emission rate in 2005 was also higher than the WKE Plan 8A emission rate. These actual emission rate values would result in a higher NO_x emission for the OTAG season. Specifically, the Coleman units did not achieve the NO_x reduction efficiencies as noted in the settlement agreement between WKE and Mobotec. An alternate SNCR control strategy was offered by Mobotec to WKE for implementation on the Coleman unit(s) in recognition of the need to further reduce NO_x emissions.

3. Additional NO_x emissions due to other events. WKE Plan 8A did not include additional NO_x emissions due to such events as SCR warm up periods and operation of the Wilson Unit Pulverizer No. 3. These actual emissions would result in a higher NO_x emission than planned for the OTAG season.

4. Planned and forced outages. The WKE Plan 8A did not include additional NO_x emissions due to the loss of specific units equipped with SCRs or higher efficiency NO_x removal equipment. The results are more NO_x emissions being generated than planned.

Section 4

Alternative NO_x Compliance - WKE Plan 5B Review

Introduction

Stanley Consultants reviewed the performance of WKE Plan 5B utilizing the data developed for the 2004 and 2005 OTAG seasons. Information and data provided to BREC and Stanley Consultants at the January 5, 2006, NO_x Compliance Review Meeting was utilized in the review. A comparison of the WKE Plan 5B assumptions and performance and an analysis of the actual unit performances conditions are provided below.

Description of WKE Plan 5B

WKE Plan 5B, as proposed by WKE, included the installation of five SCR systems on the Wilson, Green, and HMPL units. The plan included the conversion of the Reid Unit 1 from a coal-fired unit to a co-fired unit utilizing both natural gas and coal. The Reid CT would be operated with natural gas instead of No. 2 oil during the OTAG season. The Coleman, HMPL, Green, and Wilson units would receive control system upgrades which included DCS and NN systems. The projected NO_x removal efficiencies for the methods of reduction as noted above utilized in the WKE Plan 5B evaluation and model run were:

- The Wilson Unit methods of reduction were SCR/DCS/NN/BOP resulting in a combined 90 percent removal efficiency.
- The Green Units would utilize SCR/DCS/NN/BOP resulting in a combined 90 percent removal efficiency.
- The HMPL Units would utilize SCR/DCS/NN/BOP resulting in a combined 90 percent removal efficiency.
- The Coleman Units would utilize DCS/NN/Field Devices resulting in a combined 10 percent removal efficiency.

- The method of reduction selected for Reid Unit 1 was identified as a fuel switch to co-firing natural gas with coal (50 percent gas-fired) resulting in a 81.71 percent removal efficiency.

- The method of reduction selected for the Reid CT was identified as a fuel switch to firing natural gas. The implementation of this change would afford the ability to burn either No. 2 fuel oil or natural gas. Burning natural gas during the OTAG season would result in a 83.15 percent removal efficiency.

The system NO_x emissions were determined from the spreadsheet developed by WKE which modeled the WKE Plan5B. The projected NO_x emissions for each OTAG season were determined to be 4,488 tons utilizing the WKE model assumptions. This level of NO_x emissions complies with the Kentucky SIP regulatory allotment of 4,571 tons for the BREC system as noted in Table 4-1 below. In addition, each OTAG season would generate an additional 83 allowances (2 percent) which could be banked or sold. Actual plant operating and emissions data for the first quarter of 2001 and the years of 2000 and 1997 were utilized as a baseline to determine the modeled emissions results for the non-OTAG season and are reported below in Table 4-1 as the Year 2000 Average NO_x values for each of the units. The data for the year 1997 represent the last full year the generating units were operated by BREC. A copy of the WKE Plan 5B Spreadsheet is included in Appendix E. Table 4-1 summarizes the results from WKE Plan 5B:

Table 4-1 WKE Plan 5B – NO_x Reduction Technologies

	WKE Plan 5B			
Unit	**Technology**	**Year 2000 Average NO_x lb/mmBtu**	**Emissions after Control lb/mmBtu**	**Removal Efficiency**
Coleman Unit 1	DCS/NN/Field Devices	0.420	0.378	10.00%
Coleman Unit 2	DCS/NN/Field Devices	0.428	0.385	10.00%
Coleman Unit 3	DCS/NN/Field Devices	0.417	0.375	10.00%
HMPL Unit 1(1)	SCR/BOP	0.457	0.046	90.00%
HMPL Unit 2(1)	SCR/BOP	0.478	0.048	90.00%
Green Unit 1	SCR/DCS/NN/BOP	0.412	0.041	90.00%
Green Unit 2	SCR/DCS/NN/BOP	0.422	0.042	90.00%
Wilson Unit	SCR/DCS/NN/BOP	0.431	0.043	90.00%
Reid Unit 1	50% Gas-Fired	0.812	0.149	81.71%
Reid CT	Gas-Fired	0.890	0.150	83.15%
Target NO_x	4,571	---	---	---
NO_x Emissions, tons	4,488	---	---	---
Capital Cost, $1,000,000	170.5	---	---	---

Notes:
(1) The NO_x reduction technologies listed in this table for HMPL Unit 1 and HMPL Unit 2 were obtained from the WKE Plan 5B spreadsheet.

WKE Sources of Data

The following sources of data were utilized by WKE in the development of WKE Plan 5B.

1. S&L 1999 NO_x Compliance Study.
2. WKE evaluation of potential suppliers of NN control systems.
3. WKE's Base Case Plan 5 results which utilized baseline performance data from 1997, 2000 and the first quarter of 2001.

WKE Assumptions

WKE assumptions utilized in the development of Plan 5B follow:

1. Projected NO_x reductions are documented in Table 4-1.
2. Capital costs were revised to reflect the latest contractor and/or vendor negotiations.
3. Annual catalyst costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study.
4. The first year fixed O&M costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study. These costs were adjusted for escalation at a rate of 3 percent per year.
5. The variable O&M costs utilized in the plan were based on information obtained from the S&L NO_x Compliance Study.
6. An adjusted ammonia cost of $350 per ton was utilized.
7. The OTAG season capacity factors utilized in the plan development were 90 percent for all BREC and HMPL units with the only exceptions being the Reid Unit 1 and the Reid CT which utilized capacity factors of 85 percent.
8. Contingency cost estimates which are typical of these types of analysis were eliminated from the compliance plan cost projections.
9. NO_x emission reductions from 14,000 tons to less than 4,600 tons were to occur during the OTAG season beginning in May 2004.
10. The WKE models assumed a purchase price of $2,500 per ton for each NO_x emission allowance.
11. WKE Plan 5B assumed 100 percent availability for all of the units during the OTAG season.

12. Data presented in the WKE Plan 5B spreadsheet indicates "through 2000 CEM heat rates" were used.

13. Baseline Performance Tests were performed by Babcock Borsig Power during the year 2000 on the Green Units and the Wilson Unit. These tests provided data which was utilized in the sizing calculations for the future SCRs and selection of the proper catalyst type. The SCR baseline testing utilized coal as the fuel for the Green Units. The SCR baseline testing utilized the following fuel blends for the tests performed on the Wilson unit :

    - 75 Percent Pet Coke/25 Percent Bituminous Coal
    - 40 Percent Pet Coke/60 Percent Bituminous Coal
    - 0 Percent Pet Coke/100 Percent Bituminous Coal

14. Baseline Performance Tests were performed by Clean Air Engineering during the year 2002 on the HMPL Units. The testing was performed utilizing the following fuel blends:

    - 80 Percent Pet Coke/20 Percent Bituminous Coal
    - 60 Percent Pet Coke/40 Percent Bituminous Coal
    - 0 Percent Pet Coke/100 Percent Bituminous Coal

WKE Plan 5B Performance

2004 and 2005 OTAG Season Evaluation

2004 and 2005 OTAG Season Model Parameters

The WKE actual generation and NO_x emissions for the OTAG season of 2004 and 2005 are documented in Section 3, Tables 3-1 and 3-2. These values were then compared to the WKE Plan 5B anticipated budgets for the respective years and the differences are noted.

WKE Plan 5B Model Parameters

WKE Plan 5B spreadsheet description and parameters are as follows.

1. The OTAG season energy production in kWh is a calculated value developed for each unit from the product of gross capacity generation in kW times the average capacity factor times the OTAG season hours.

2. The CEM heat rates expressed in Btu/kWh for the calendar year 2000 were utilized.

3. WKE assumed 100 percent availability for all units. A 90 percent capacity factor was utilized for the Coleman, HMPL, Green, and Wilson Units. An 85 percent capacity factor was assumed for Reid Unit 1 and the Reid CT.

4. WKE utilized the average emission rates expressed in lbs/mmBtu for the calendar year 2000 for each unit. These same average emission rates were utilized in the WKE Plan 8A.

5. The projected NO_x reductions utilized in the plan are documented in Table 4-1.

6. Each OTAG season represented 3,672 hours which occurred in months of May through September and were utilized in the spreadsheet calculations.

2004 and 2005 OTAG Season Model Evaluation

The WKE Plan 5B spreadsheet was utilized in determining variations from the original plan assumptions in the evaluation of the actual 2004 and 2005 OTAG season performances. The following parameters were utilized in the evaluation of the 2004 and 2005 OTAG season performances.

1. The 2004 and 2005 actual gross energy production documented in Section 3, Tables 3-1 and 3-2 for each respective OTAG season (adjusted for the 2004 OTAG beginning May 31) was utilized as data input in 2004 and 2005 OTAG Season WKE Plan 5B model runs.

2. WKE actual 2004 and 2005 gross heat rates were utilized in the 2004 and 2005 OTAG Season WKE Plan 5B models as documented in Section 3, Table 3-5.

3. Stanley Consultants determined the number of forced outage hours and planned outage hours during the 2004 and 2005 OTAG seasons from the 2004 and 2005 production outage reports. The 2004 OTAG season consisted of the total hours beginning on May 31 through September 30. For 2005, the OTAG season began May 1 and ended on September 30. The number of hours of availability for each unit is documented in Section 3, Table 3-6.

4. Actual emission rates by unit were utilized in the 2004 and 2005 OTAG season evaluation. Table 4-2 compares WKE Plan 5B assumed emission rates and WKE Plan 8A assumed emission rates to the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.

Table 4-2 Emission Rates (lbs/mmBtu)

Unit	WKE Plan 5B Assumed Emission Rates	WKE Plan 8A Assumed Emission Rates	Actual 2004 Emission Rates(1)	Actual 2005 Emission Rates(1)
Coleman Unit 1	0.378	0.223	0.293	0.306
Coleman Unit 2	0.385	0.227	0.284	0.296
Coleman Unit 3	0.375	0.221	0.289	0.299
HMPL Unit 1	0.046	0.046	0.051(2)	0.056(2)
HMPL Unit 2	0.048	0.048	0.038(2)	0.055(2)
Green Unit 1	0.041	0.206	0.203	0.205
Green Unit 2	0.042	0.211	0.198	0.209
Wilson Unit	0.043	0.043	0.043(2)	0.037(2)
Reid Unit 1	0.149	0.149	0.260	0.403
Reid CT(3)	0.150	0.150	0.150	0.150

Notes:
(1) Provided by WKE in the "04 05 Ozone Season Emission Rates.xls" spreadsheet. The average of the months of the OTAG season were used.
(2) The emission rates used for HMPL Units 1 and 2 and Wilson Unit are exclusive of SCR events.
(3) Actual 2004 and 2005 emission rate data is not available. The emission rate documented in WKE Plan 8A was utilized.

Generation Impacts to WKE Plan 5B Assumptions

WKE Plan 5B Excel spreadsheet was utilized in calculating variations from the original plan assumptions in the review of the actual performance of the WKE Plan 5B for the 2004 and 2005 OTAG seasons. Data input to the spreadsheet was obtained from several sources to determine the impact of the historical data on the WKE Plan 5B performance.

Capacity Factors

Capacity factors utilized for each unit were calculated utilizing the actual WKE OTAG season gross energy production in MWhs, the gross capacity, and the hours of operation. Table 4-3 documents a comparison between capacity factors calculated from actual gross energy production in MWhs and the original capacity factors assumed in the WKE Plan 5B.

Table 4-3 Gross Capacity Factors - OTAG Season

Unit	Assumed WKE Plan 5B	Calculated from 2004 Actual Gross Energy Produced(1)	Calculated from 2005 Actual Gross Energy Produced(2)
Coleman Unit 1	90.0%	76.4%	79.2%
Coleman Unit 2	90.0%	79.9%	73.2%
Coleman Unit 3	90.0%	75.8%	76.1%
HMPL Unit 1	90.0%	89.9%	94.6%
HMPL Unit 2	90.0%	86.1%	88.6%
Green Unit 1	90.0%	95.2%	100.0%
Green Unit 2	90.0%	96.7%	98.6%
Wilson Unit	90.0%	94.8%	98.3%
Reid Unit 1	85.0%	55.8%	78.8%
Reid CT	85.0%	33.4%	30.8%

Notes:
(1) Calculated from Actual 2004 OTAG season gross energy produced kWh (adjusted for OTAG season beginning May 31) divided by the gross capacity of the unit divided by the hours in operation.
(2) Calculated from Actual 2005 OTAG season gross energy produced kWh divided by the gross capacity of the unit divided by the hours in operation.

Heat Rate Impacts to WKE Plan 5B Assumptions

Actual gross heat rates were used in the 2004 and 2005 OTAG season evaluations as documented in Section 3, Table 3-5. WKE Plan 5B original heat rates are the same as the original heat rates utilized in WKE Plan 8A.

Unit Availability Impacts

Actual unit availability during the 2004 and 2005 OTAG seasons was determined for each unit through a review of the 2004 and 2005 production outage reports. Both forced outage hours and planned outage hours were determined and documented in a spreadsheet by unit to determine the impact(s). Specific forced outage and planned outage events by unit for the 2004 OTAG season and the 2005 OTAG season were identified and documented in Appendix C. A documentation of the summary of these events for the 2004 and 2005 OTAG season which effect unit availability are presented in Section 3, Table 3-6. The WKE Plan 5B assumed no outages during the OTAG season.

Unit Starts

The actual number of starts by unit for the 2004 and 2005 OTAG seasons is documented in Section 3, Table 3-7. The WKE Plan 5B assumes no unit starts during the OTAG season. The 2004 and 2005 OTAG Season evaluation model runs assume no unit starts during the OTAG seasons.

Results

The following results were developed from the 2004 OTAG Season evaluation versus the WKE Plan 5B assumptions:

1. Table 4-4 compares the 2004 WKE reported NO_x emissions, the 2004 OTAG Season Plan 5B modeled NO_x emissions, the WKE additional tons of NO_x due to extraordinary events (2004 OTAG Additional NO_x Events), the WKE Plan 5B NO_x emissions, and the WKE Plan 8A NO_x emissions.

Table 4-4 2004 OTAG Season Evaluation – WKE Plan 5B

Unit	WKE Reported 2004 NO_x Tons(1)	2004 OTAG Season Evaluation			Projected WKE Plan 5B NO_x Tons(5)	Projected WKE Plan 8A NO_x Tons(6)
		2004 OTAG Season Plan 5B NO_x Tons(2)	2004 WKE Additional NO_x Events Tons(3)	2004 Total NO_x Tons(4)		
Coleman Unit 1	515	611.9	30.0	641.9	1,009	594
Coleman Unit 2	544	699.1	30.4	729.5	1,083	638
Coleman Unit 3	539	655.5	0.7	656.2	1,067	628
HMPL Unit 1	199	84.4	80.6	165.0	132	132
HMPL Unit 2	214	80.2	386.7	466.9	145	145
Green Unit 1	649	129.9	12.4	142.3	165	825
Green Unit 2	683	139.9	45.8	185.7	171	857
Wilson Unit	421	259.0	263.5	522.5	380	380
Reid Unit 1	45	24.2	0.4	24.6	172	171
Reid CT	47	2.9	---	2.9	164	164
Total	3,856	2,687.0	850.5	3,537.5	4,488	4,534
Excess NO_x Allowances (Tons)	644	1,813.0	---	962.5	83	37
Additional NO_x Allowances Needed (Tons)	---	---	---	---	---	---
Allocated NO_x Allowances	4,500	4,500	---	4,500	4,571	4,571

Notes:

(1) Values were provided in the WKE spreadsheet entitled "2004 NO_x Actuals Compared to Budget" Refer to Appendix G.

(2) Values were calculated in the 2004 OTAG Season Evaluation using 2004 information presented in Tables 4-2 and 4-3 and Section 3, Tables 3-1 and 3-2.

(3) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were obtained from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls."

(4) This is a calculated value from the sum of "2004 OTAG Season Plan 5B NO_x Tons" column and "2004 WKE Additional NO_x Events Tons" column.

(5) Values were provided in the WKE Plan 5B Spreadsheet. Refer to Appendix F

(6) Values were provided in the WKE Plan 8A Spreadsheet. Refer to Appendix E

a. The difference noted in the "WKE Reported 2004 NO_x Tons" column of 644 Excess NO_x Allowances and the "2004 Total NO_x Tons" column of 962.5 Excess NO_x Allowances from the 2004 OTAG Season Evaluation are attributed to differences in heat rate and emission rates for the units. A discussion of each of these parameters follows:

   (1) The 2004 OTAG Season Evaluation Plan 5B Spreadsheet used WKE Annual Gross Heat Rates. The WKE Plan 5B spreadsheet utilized 2000 CEM Heat Rates. Unit heat rates have an impact on the calculated NO_x emissions.

   (2) The 2004 OTAG Season Evaluation Plan 5B spreadsheet used actual emission rates versus the WKE Plan 5B assumed emission rates. Removal efficiencies based on the actual emission rates are less than the assumed emissions rates for the following units:

      (a) Reid Unit 1 – The strategy of fuel switching (from coal to natural gas) was projected to result in a NO_x emissions removal efficiency of 81.71 percent. Current removal efficiency using the FGR system and the installation of natural gas burners on the top burner elevation and utilizing the cooling air as over fired air results in a removal efficiency of 67.98 percent.

      (b) HMPL Unit 1 - WKE Plan 5B removal efficiency was projected to be 90 percent. Actual emission rates indicate the removal efficiency is 88.84 percent. The continuing startup activities and other contractual issues have prevented final tuning of the SCR system.

b. WKE provided information regarding additional tons of NO_x emissions due to other events to BREC in a meeting held on January 5, 2006. A detailed breakdown of these events and the additional tons of NO_x per event are included in Appendix D. A discussion of the events follows:

   (1) WKE reported in a spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" the additional NO_x emissions of 61.56 tons for "SCR warm up period" due to startup activities which occurred after a forced outage event at the Wilson unit during the 2004 OTAG season. WKE's spreadsheet indicated the Wilson unit SCR was off-line for 85 hours due to warm up activities after the outage events.

   (2) In 2004, WKE reported that the Wilson unit Pulverizer No. 3 operated 1,209 hours. WKE provided an emission rate of 0.127193 tons of NO_x per hour resulting from the operation of the Pulverizer No. 3 during the OTAG season. The additional operation of the Pulverizer No. 3 resulted

in 154 tons of additional NO_x emissions that had not been anticipated in the WKE Plan 5B.

2. The 2004 gross capacity factors were calculated using 2004 gross energy production. Green Units 1 and 2 and Wilson Unit capacity factors were higher than the WKE Plan 5B capacity factors. The 2004 System Gross Capacity Factor average was 78.4 percent compared to WKE Plan 5B System Gross Capacity Factor average of 89 percent. The specific unit capacity factors will create additional NO_x emissions for those units not equipped with SCRs, when those factors are higher than the original plan or budget.

3. The actual 2004 gross heat rates resulted in lower values as compared to those utilized in the WKE Plan 5B except for Reid Unit 1.

4. WKE Plan 5B projected a 3,672-hour OTAG season and assumed 100 percent availability for all the units. The 2004 OTAG season of May 31 through September 30 was only 2,952 hours, which contributed to the excess allowances reported by WKE. Review of the production outage reports indicates that Coleman Unit 1 and Reid Unit 1 were off-line for planned outages (PO) for a period of time during the 2004 OTAG season. All units were off-line at one time or another due to forced outages during the 2004 OTAG season.

5. A discussion of the HMPL Unit 1 low water boiler event which occurred in August, 2004 is documented in Section 3 under the heading of "Results".

6. A summary of additional 2004 and 2005 NO_x emissions information provided by WKE is documented in Appendix D.

7. A discussion of the accuracy of the NO_x analyzers is documented in Section 3 under the heading of "Results".

8. A discussion of the additional NO_x emissions resulting from the Wilson Unit Pulverizer No. 3 operation is documented in Section 3 under the heading of "Results".

The following results were derived from the 2005 OTAG Season evaluation:

1. Table 4-5 compares the 2005 WKE reported NO_x emissions, the 2005 OTAG Season Plan 5B modeled NO_x emissions, the WKE additional tons of NO_x due to extraordinary events (2005 OTAG Additional NO_x Events), the WKE Plan 5B NO_x emissions, and the WKE Plan 8A NO_x emissions.

Table 4-5 2005 OTAG Season Evaluation - WKE Plan 5B

Unit	WKE Reported 2005 NO_x Tons (1)	2005 OTAG Season Evaluation			Projected WKE Plan 5B NO_x Tons (5)	Projected WKE Plan 8A NO_x Tons (6)
		2005 OTAG Season Plan 5B NO_x Tons (2)	2005 WKE Additional NO_x Events Tons (3)	2005 Total NO_x Tons (4)		
Coleman Unit 1	737	812.3	38.8	851.1	1,009	594
Coleman Unit 2	636	793.0	5.5	798.5	1,083	638
Coleman Unit 3	757	810.2	83.8	894.0	1,067	628
HMPL Unit 1	213	149.7	53.2	202.9	132	132
HMPL Unit 2	204	142.8	65.9	208.7	145	145
Green Unit 1	888	181.7	(1.5)	180.2	165	825
Green Unit 2	882	173.6	37.5	211.1	171	857
Wilson Unit	424	288.1	130.3	418.4	380	380
Reid Unit 1	433	298.0	57.4	355.4	172	171
Reid CT	23	1.5	---	1.5	164	164
Total	5,195	3,650.9	470.9	4,121.8	4,488	4,534
Excess NO_x Allowances (Tons)	---	849.1	---	378.2	83	37
Additional NO_x Allowances Needed (Tons)	695	---	---	---	---	---
Allocated NO_x Allowances	4,500	4,500	---	4,500	4,571	4,571

Notes:

(1) Values were provided in the WKE spreadsheet entitled "2005 NO_x Actuals Compared to Budget" Refer to Appendix G.

(2) Values were calculated in the 2005 OTAG Season Evaluation using 2005 information presented in Tables 4-2 and 4-3 and Section 3, Tables 3-1 and 3-2.

(3) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were obtained from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls"

(4) This is a calculated value from the sum of "2005 OTAG Season Plan 5B NOx Tons" column and "2005 WKE Additional NOx Events Tons" column.

(5) Values were provided in the WKE Plan 5B Spreadsheet. Refer to Appendix F.

(6) Values were provided in the WKE Plan 8A Spreadsheet. Refer to Appendix E.

a. The difference noted in the "WKE Reported 2005 NO_x Tons" column of 695 Additional NO_x Allowances Needed and the "2005 Total NO_x Tons" column of 378.2 Excess NO_x Allowances from the 2005 OTAG Season Evaluation are attributed to differences in heat rate and emission rates as well as the Green Units being equipped with SCR systems as a NO_x reduction technology (90 percent removal efficiency) under WKE Plan 5B. A discussion of each of these parameters follows:

(1) The 2005 OTAG Season Evaluation Plan 5B Spreadsheet used WKE Annual Gross Heat Rates. The WKE Plan 5B spreadsheet utilized 2000 CEM Heat Rates. Actual unit heat rates have an impact on the tons calculated.

(2) The 2005 OTAG Season Evaluation Plan 5B spreadsheet used actual emission rates versus the WKE Plan 5B assumed emission rates. Removal efficiencies based on the actual emission rates are less than the assumed emission rates for the following units:

1. Reid Unit 1 – The strategy of fuel switching (from coal to natural gas) was projected to result in a NO_x emissions removal efficiency of 81.71 percent. Current removal efficiency using the FGR system and the installation of natural gas burners on the top burner elevation and utilizing the cooling air as over fired air results in a removal efficiency of 50.37 percent.

2. HMPL Units 1 and 2 – The WKE Plan 5B removal efficiency was projected to be 90 percent. Actual emission rates indicate the removal efficiencies are 87.75 percent and 88.49 percent, respectively. The continuing startup activities and other contractual issues have prevented final tuning of these SCR systems.

b. WKE provided information regarding additional tons of NO_x emissions due to other events to BREC in a meeting held on January 5, 2006. A detailed description of these events and the additional tons of NO_x per event are documented in Appendix D. A discussion of these events follows:

(1) WKE reported in a spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" the additional NO_x emissions of 82.14 tons for "SCR warm up period" occurred due to startup activities after forced outages on the Wilson unit during the 2005 OTAG season. WKE's spreadsheet indicated the Wilson unit SCR was off-line for 113 hours due to warm up activities after outage events.

(2) In 2005, the additional operation of the Wilson Unit Pulverizer No. 3 resulted in 30.51 tons of additional NO_x emissions that had not been anticipated in the WKE Plan 5B.

2. The 2005 gross capacity factors were calculated utilizing 2005 gross energy production. Green Units 1 and 2, HMPL Unit 1, and Wilson Unit gross capacity factors were higher than WKE Plan 5B capacity factors. The 2005 System Gross Capacity Factor average was 81.87 percent compared to WKE Plan 5B System Gross Capacity Factor average of 89 percent. The specific unit capacity factors will create

additional NO_x emissions for those units not equipped with SCRs, when those factors are higher than the original plan or budget.

3. The actual 2005 gross heat rates resulted in lower values as compared to those utilized in the WKE Plan 5B except for Green Unit 1 and Reid Unit 1.

4. WKE Plan 5B assumes 100 percent availability for all the units. Review of the production outage reports indicates that Green Units 1 and 2, HMPL Unit 2 and Reid Unit 1 were off-line for planned outages (PO) or deferred maintenance (U04) for a period of time during the 2005 OTAG season. All units were off-line at one time or another due to forced outages during the 2005 OTAG season.

5. A discussion of the accuracy of the NO_x analyzers is included in Section 3 under the heading of "Results".

6. The HMPL Units and the Wilson Unit were off-line due to forced outages or planned outages for a total of 672 hours during the 2005 OTAG season, or approximately 18 percent of the OTAG season period. These units are equipped with SCRs resulting in higher NO_x removal efficiencies. Thus, during the 2005 OTAG season there is a large reliance on other generating units with less efficient NO_x removal equipment.

7. HMPL Unit 1 and the Wilson Unit were off-line approximately 268 hours of the total 672 hours (approximately 40 percent of the period) in August, 2005, due to repeated tube leaks.

8. A summary of additional 2004 and 2005 NO_x emissions information provided by WKE is provided in Appendix D.

9. Table 4-6 compares the 2004 and 2005 OTAG Season for WKE Plan 5B and 2004 and 2005 OTAG season for WKE Plan 8A modeled NO_x emissions.

Table 4-6 2004 and 2005 OTAG Season - Plan 5B and Plan 8A Comparison

Unit	2004 OTAG Season				2005 OTAG Season			
	Plan 5B NO_x Tons[1]	Plan 8A NO_x Tons[2]	Difference[3]	Difference %[4]	Plan 5B NO_x Tons[5]	Plan 8A NO_x Tons[6]	Difference[7]	Difference %[8]
Coleman Unit 1	611.9	474.3	137.6	22.5	812.3	658.5	153.9	18.9
Coleman Unit 2	699.1	514.9	184.1	26.3	793.0	609.8	183.2	23.1
Coleman Unit 3	655.5	505.2	150.3	22.9	810.2	646.4	163.9	20.2
HMPL Unit 1	84.4	84.2	0.2	0.3	149.7	148.9	0.8	0.5
HMPL Unit 2	80.2	79.4	0.8	1.0	142.8	143.6	(0.9)	(0.6)
Green Unit 1	129.9	638.5	(508.6)	(79.7)	181.7	904.7	(723.1)	(79.9)
Green Unit 2	139.9	654.6	(514.7)	(78.6)	173.6	859.1	(685.5)	(79.8)
Wilson Unit	259.0	257.0	2.0	0.8	288.1	287.1	0.9	0.3
Reid Unit 1	24.2	24.2	0.0	0.1	298.0	298.0	0.0	0.0
Reid CT	2.9	2.9	0.0	0.0	1.5	1.5	0.0	0.0
TOTAL	2,687.0	3,235.2	(548.3)	(16.9)	3,650.9	4,557.6	(906.7)	(19.9)
Excess NO_x Allowances (Tons)	1,813.0	1,264.8	548.3	30.2	849.1	--	906.7	106.8
Additional NO_x Allowances Needed (Tons)	--	--	--	--	--	57.6	--	--
Allocated NO_x Allowances	4,500	4,50	--	--	4,500	4,500	--	--

Notes:

(1) Values were calculated in the Plan 5B 2004 OTAG Season Evaluation using 2004 information presented in Tables 4-2 and 4-3 and Section 3, Tables 3-1 and 3-2.

(2) Values were calculated in the Plan 8A 2004 OTAG Season Evaluation using 2004 information presented in Tables 3-1 through 3-6.

(3) This value is a calculated value. The calculated value takes the controlled tons from the 2004 "Plan 5B NO_x Tons" column and subtracts the controlled tons from the 2004 "Plan 8A NO_x Tons" column.

(4) This value is a calculated value. The 2004 "Difference" column is divided by the 2004 "Plan 5B NO_x Tons" column for positive values. The 2004 "Difference" column is divided by the 2004 "Plan 8A NO_x Tons" column for negative values.

(5) Values were calculated in the Plan 5B 2005 OTAG Season Evaluation using 2005 information presented in Tables 4-2 and 4-3 and Section 3, Tables 3-1 and 3-2.

(6) Values were calculated in the Plan 8A 2005 OTAG Season Evaluation using 2005 information presented in Tables 3-1 through 3-6.

(7) This value is a calculated value. The calculated value takes the controlled tons from the 2005 "Plan 5B NO_x Tons" column and then subtracts the controlled tons from the 2005 "Plan 8A NO_x Tons" column.

(8) This value is a calculated value. The 2005 "Difference" column is divided by the 2005 "Plan 5B NO_x Tons" season evaluation for positive values. The 2005 "Difference" column is divided by the 2005 Plan 8A NO_x Tons" column for negative values.

Conclusions

WKE Plan 5B would provide for compliance during the 2004 and 2005 OTAG seasons as additional NO_x would be removed due to the installation of SCRs on the Green Units. The difference in additional NO_x emissions removed would compensate for any increases which were observed in the 2004 and 2005 OTAG seasons resulting from differences in specific unit heat rates, differences in specific unit emission rates, additional NO_x emissions due to other events, and planned and forced outages.

Section 5

WKE Plan 8A - Future Performance

Introduction

Stanley Consultants evaluated the WKE Plan 8A for the 2007 and 2008 OTAG seasons under a range of operating scenarios. The WKE Plan 8A spreadsheet was utilized in calculating variations in operating scenarios in the evaluation of the future 2007 and 2008 OTAG season projected performance. The existing WKE Compliance Plan 8A was evaluated to determine if the plan will allow the BREC system to "take care of itself". The evaluation assumed that the BREC system is to "break even" with regard to tons of NO_x emitted versus available NO_x allowances at the end of an OTAG season considering reasonable and conservative contingencies.

Stanley Consultants reviewed the past generation capacity factors, availability factors and heat rate information provided by WKE for previous Annual Condition Assessment Reports was conducted. This information was utilized to develop future anticipated capacity and availability factors and heat rate impacts for evaluation of future compliance. In addition, a review of the future planned and unplanned outages provided by BREC was performed and an estimate of the effect to capacity and availability factors and heat rates of the units was determined.

Finally, a sensitivity analysis was performed to aid in identifying any future operational exposures. Any allowance deficit identified was converted into a cost exposure.

Operating Scenarios

The following operating scenarios were analyzed:

- 100 Percent Availability Case: All units were assumed to be 100 percent available with the exception of the Reid CT. Separate model runs were developed using:

  - Current emission rates.
  - WKE Plan 8A emission rates.

- Base Case: A base case model run was analyzed utilizing information from the BREC Production Cost Report. Separate model runs were made using:
  - Current emission rates.
  - WKE Plan 8A emission rates.

- Sensitivity Cases:
  - The Case 1 model run consisted of each unit with a 50 percent availability. A model run was developed for each of the nine generating units. Additional separate model runs were made using:
    - Current emission rates.
    - WKE Plan 8A emission rates.
  - The Case 2 model run consisted of each unit with an increase in heat rate for that unit of 400 Btu/kWh. A model run was developed for each of the nine generating units. Additional separate model runs were made using:
    - Current emission rates.
    - WKE Plan 8A emission rates.

Future Generation Performance Parameters

100 Percent Availability Case

The parameters utilized in the 100 Percent Availability Case evaluation are as follows:

1. Availability factors are assumed to be 100 percent during the 2007 and 2008 OTAG seasons for all units except for the Reid CT. The Reid CT availability was assumed to be zero during the 2007 and 2008 OTAG seasons.

2. The OTAG season of May 1 through September 30, total 3,672 hours.

3. Capacity factors are assumed to be 90 percent during the OTAG season for all units except for the Reid Unit 1. The capacity factor assumed for the Reid Unit 1 is 85 percent. These are the same capacity factors used in WKE Plan 8A. See Table 3-4.

4. Heat rates for 2007 and 2008 were obtained from the BREC Production Cost Report and were utilized in the WKE Plan 8A spreadsheet model runs. Tables 5-1 and 5-2 depict the 2007 and 2008 net heat rates utilized for each unit in the development of

the WKE Plan 8A model runs. The heat rates reflect expected improvement to the Green Unit 1, Coleman Units 1 and 2, and the Wilson Unit due to future turbine-generator overhauls and the anticipated performance improvement. The future overhauls are scheduled for the noted years as follows:

   a. Coleman Unit 1 in 2008

   b. Coleman Unit 2 in 2007

   c. Green Unit 1 in 2006

   d. Wilson Unit in 2008

4. The net continuous maximum capacities for each unit were obtained from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006. The net capacities are used in the calculation of the net generating energy. Tables 5-1 and 5-2 document these capacities.

5. The 100 Percent Availability cases were developed using two input data sets of removal efficiencies and emission rates to determine the impact of each on the total OTAG season NO_x emissions. Tables 5-1 and 5-2 document the Current and WKE Plan 8A removal efficiencies and emission rates used by unit.

   a. The average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE are utilized as the current emission rates. Actual removal efficiencies and emission rates by unit represents one set of input data utilized in the analysis.

   b. The assumed removal efficiencies and emission rates by unit utilized in the WKE Plan 8A were the second set of input data utilized in the analysis.

6. The 2007-2008 NO_x OTAG season credit allotment of 4,799 tons was utilized in the analysis. The information was obtained from the Commonwealth of Kentucky, Department for Environmental Protection, Division for Air Quality and is published on their website at:

   http://www.air.ky.gov/news/Kentucky+2007-2008+NOx+Allocations.htm

7. The net generating energy is a calculated value and is the product of the Net Capacity times the Available Hours times the Capacity Factor.

Tables 5-1 and 5-2 document the 2007 and 2008 100 Percent Availability Case evaluation parameters.

Table 5-1 2007 100% Availability Case Plan 8A Parameters

Unit	Availability Factor(1)	Net Capacity Factors(2)	Net Heat Rate (Btu/ kWh)(3)	Net Continuous Maximum Capacity (MW)(4)	Removal Efficiency		Emission Rates (lb/mmBtu)	
					Average Actual 2004-05(5)	WKE Plan 8A Assumed(6)	Average Actual 2004-05(7)	WKE Plan 8A Assumed(8)
Coleman Unit 1	100%	90%	10,984	144.6	28.57%	47.00%	0.300	0.223
Coleman Unit 2	100%	90%	10,755	145.0	32.24%	47.00%	0.290	0.227
Coleman Unit 3	100%	90%	10,582	150.0	29.50%	47.00%	0.294	0.221
HMPL Unit 1	100%	90%	10,570	152.2	88.40%	90.00%	0.053	0.046
HMPL Unit 2	100%	90%	10,743	158.2	90.38%	90.00%	0.046	0.048
Green Unit 1	100%	90%	10,509	231.0	50.49%	50.00%	0.204	0.206
Green Unit 2	100%	90%	10,531	223.0	51.90%	50.00%	0.203	0.211
Wilson Unit	100%	90%	10,824	416.8	90.72%	90.00%	0.040	0.043
Reid Unit 1	100%	85%	11,869	65.0	59.24%	81.71%	0.331	0.149
Reid CT	0%	85%	13,347	65.0	83.15%	83.15%	0.150	0.150

Notes:

(1) Based on the units operating 100 percent of the time.

(2) Based on the same capacity factors as WKE Plan 8A.

(3) Net heat rates from the BREC Production Cost Report.

(4) Rated for the OTAG season. Capacities are from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006.

(5) Removal efficiencies based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.

(6) Removal efficiencies provided in WKE Plan 8A spreadsheet. Refer to Appendix E.

(7) Actual emission rates are based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE. Emission rates exclusive of SCR events were used for HMPL Units 1 and 2 and the Wilson Unit.

(8) Emission rates provided in WKE Plan 8A spreadsheet.

Table 5-2 2008 100% Availability Case Plan 8A Parameters

Unit	Availability Factor(1)	Net Capacity Factors(2)	Net Heat Rate (Btu/ kWh)(3)	Net Continuous Maximum Capacity (MW)(4)	Removal Efficiency		Emission Rates (lb/mmBtu)	
					Average Actual 2004-05(5)	WKE Plan 8A Assumed(6)	Average Actual 2004-05(7)	WKE Plan 8A Assumed(8)
Coleman Unit 1	100%	90%	10,952	144.6	28.57%	47.00%	0.300	0.223
Coleman Unit 2	100%	90%	10,515	145.0	32.24%	47.00%	0.290	0.227
Coleman Unit 3	100%	90%	10,589	150.0	29.50%	47.00%	0.294	0.221
HMPL Unit 1	100%	90%	10,411	152.2	88.40%	90.00%	0.053	0.046
HMPL Unit 2	100%	90%	10,641	158.2	90.38%	90.00%	0.046	0.048
Green Unit 1	100%	90%	10,518	231.0	50.49%	50.00%	0.204	0.206
Green Unit 2	100%	90%	10,539	223.0	51.90%	50.00%	0.203	0.211
Wilson Unit	100%	90%	10,348	416.8	90.72%	90.00%	0.040	0.043
Reid Unit 1	100%	85%	11,867	65.0	59.24%	81.71%	0.331	0.149
Reid CT	0%	85%	13,347	65.0	83.15%	83.15%	0.150	0.150

Notes:

(1) Based on the units operating 100 percent of the time.
(2) Based on the same capacity factors as WKE Plan 8A.
(3) Net heat rates from the BREC Production Cost Report.
(4) Rated for the OTAG season. Capacities are from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006.
(5) Removal efficiencies based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.
(6) Removal efficiencies provided in WKE Plan 8A spreadsheet. Refer to Appendix E.
(7) Actual emission rates are based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE. Emission rates exclusive of SCR events were used for HMPL Units 1 and 2 and the Wilson Unit.
(8) Emission rates provided in WKE Plan 8A spreadsheet.

Base Case

The parameters utilized in the development of the Base Case evaluation are as follows:

1. Availability factors used in the 2007 and 2008 Base Case runs were determined from the number of annual forced outage hours projected by unit in the BREC Production Cost Report. In an effort to determine the portion of the projected forced outage hours that might occur during the May 1 through September 30 OTAG season, historical data for 2000 through 2005 was reviewed and summarized. An average percentage of forced outage hours which occur during the OTAG season as a percent of the annual forced outage hours for each unit was determined for the years 2000 through 2005. The historical forced outage summary is documented in Appendix H.

2. It was assumed that no planned maintenance outages would be scheduled during the 2007 and 2008 OTAG seasons.

3. To project the amount of time the Reid Unit 1 might be on reserve standby, a 54 percent unit availability factor, provided by BREC, was used. This is the same availability as observed during the 2005 OTAG season.

4. The Reid CT availability was assumed to be zero during the 2007 and 2008 OTAG season.

5. There are 3,672 hours in the OTAG season of May 1 through September 30.

6. Capacity factors are assumed to be 90 percent during the OTAG season for all units except for Reid Unit 1. The capacity factor assumed for Reid Unit 1 is 85 percent. *These are the same capacity factors used in the original WKE Plan 8A model runs.*

7. Net heat rates for 2007 and 2008 from the BREC Production Cost Report were utilized. Tables 5-3 and 5-4 depict the 2007 and 2008 net heat rates utilized for each unit. The net heat rates reflect the expected improvement to the Green Unit 1, Coleman Units 1 and 2, and the Wilson Unit due to upcoming turbine-generator overhauls. The expected overhauls are scheduled for the following years:

   a. Coleman Unit 1 in 2008.

   b. Coleman Unit 2 in 2007.

   c. Green Unit 1 in 2006.

   d. Wilson Unit in 2008.

8. The OTAG rated net continuous maximum capacities for each unit were obtained from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006. The net capacities are used in the calculation of the net generating energy. Tables 5-3 and 5-4 document these capacities.

9. The Base Cases were developed utilizing two sets of data for the removal efficiencies and emission rates to determine the impact. Tables 5-3 and 5-4 document the actual and assumed WKE Plan 8A removal efficiencies and emission rates used for each unit.

    a. The average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE are utilized as the current emission rates. Actual removal efficiencies and emission rates by unit represents one set of input data utilized in the analysis.

    b. The assumed removal efficiencies and emission rates by unit used in the WKE Plan 8A were the second set of input data utilized in the analysis.

10. The 2007-2008 NO_x OTAG season credit allotment of 4,799 tons was utilized in the analysis. The information was obtained from the Commonwealth of Kentucky, Department for Environmental Protection, Division for Air Quality and are published on their website:

    http://www.air.ky.gov/news/Kentucky+2007-2008+NOx+Allocations.htm

11. The net generating energy is a calculated value which is the product of Net Capacity times the Available Hours times the Capacity Factor.

Tables 5-3 and 5-4 document the input data for the 2007 and 2008 Base Case evaluation parameters.

Table 5-3 2007 Base Case Plan 8A Parameters

Unit	Annual Forced Outage Hours[(1)]	2000-05 Average OTAG Season Forced Outage Hours Percent[(2)]	OTAG Season Forced Outage Hours[(3)]	OTAG Season Planned Outage Hours[(4)]	OTAG Season Available Hours[(7)]	Availability Factor[(8)]	Net Capacity Factors[(9)]	Net Heat Rates (Btu/kWh)[(10)]	Net Continuous Maximum Capacity (MW)[(11)]	Removal Efficiency		Emission Rates (lb/mmBtu)	
										Average Actual 2004-05[(12)]	WKE Plan 8A Assumed[(13)]	Average Actual 2004-05[(14)]	WKE Plan 8A Assumed[(15)]
Coleman Unit 1	193	51.44%	99.3	0.0	3,572.7	97.3%	90%	10,984	144.6	28.57%	47.00%	0.300	0.223
Coleman Unit 2	210	45.70%	96.0	0.0	3,576.0	97.4%	90%	10,755	145.0	32.24%	47.00%	0.290	0.227
Coleman Unit 3	184	35.07%	64.5	0.0	3,607.5	98.2%	90%	10,582	150.0	29.50%	47.00%	0.294	0.221
HMPL Unit 1	718	42.28%	303.6	0.0	3,368.4	91.7%	90%	10,570	152.2	88.40%	90.00%	0.053	0.046
HMPL Unit 2	482	32.01%	154.3	0.0	3,517.7	95.8%	90%	10,743	158.2	90.38%	90.00%	0.046	0.048
Green Unit 1	237	60.22%	142.7	0.0	3,529.3	96.1%	90%	10,509	231.0	50.49%	50.00%	0.204	0.206
Green Unit 2	53	39.20%	20.8	0.0	3,651.2	99.4%	90%	10,531	223.0	51.90%	50.00%	0.203	0.211
Wilson Unit	867	44.87%	389.0	0.0	3,283.0	89.4%	90%	10,824	416.8	90.72%	90.00%	0.040	0.043
Reid Unit 1	543	36.16%	196.3	1,471.7[(5)]	2,003.9	54.6%	85%	11,869	65.0	59.24%	81.71%	0.331	0.149
Reid CT	0	0.00%	0.0	3,672.0[(6)]	0.0	0.0%	85%	13,347	65.0	83.15%	83.15%	0.150	0.150

Notes:

(1) Annual forced outage hours from the BREC Production Cost Report dated 01-11-06.
(2) Expressed as a percentage of the total annual forced outage hours. Refer to Appendix H.
(3) Annual forced outage hours times the 2000-05 average OTAG season forced outage hours percent.
(4) No planned outages are projected for the OTAG season for the Wilson, Coleman, HMPL, or Green units.
(5) Reserve standby hours are projected for Reid Unit 1 using a 54.6 percent unit availability factor. The 54.6 percent availability factor is based on 2005 actual generation data provided by WKE. Refer to Appendix H.
(6) The Reid CT availability was assumed to be zero during the 2008 OTAG season.
(7) The OTAG season total hours of 3672 less the OTAG season forced outage hours and planned outage hours.
(8) The OTAG season available hours as a percent of the OTAG season total hours.
(9) Based on the same capacity factors as WKE Plan 8A spreadsheet. Refer to Appendix E.
(10) Net heat rates from the BREC Production Cost Report dated 01-11-06.
(11) Rated for the OTAG season. Capacities are from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006.
(12) Removal efficiencies based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.
(13) Assumed removal efficiencies provided in WKE Plan 8A spreadsheet. Refer to Appendix E.
(14) Actual emission rates are based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE. Emission rates exclusive of SCR events were used for HMPL Units 1 and 2 and the Wilson Unit.
(15) Assumed emission rates provided in WKE Plan 8A spreadsheet. Refer to Appendix E.

Table 5-4 2008 Base Case Plan 8A Parameters

Unit	Annual Forced Outage Hours[1]	2000-05 Average OTAG Season Forced Outage Hours Percent[2]	OTAG Season Forced Outage Hours[3]	OTAG Season Planned Outage Hours[4]	OTAG Season Available Hours[7]	Availability Factor[8]	Net Capacity Factors[9]	Net Heat Rates (Btu/kWh)[10]	Net Continuous Maximum Capacity (MW)[11]	Removal Efficiency		Emission Rates (lb/mmBtu)	
										Average Actual 2004-05[12]	WKE Plan 8A Assumed[13]	Average Actual 2004-05[14]	WKE Plan 8A Assumed[15]
Coleman Unit 1	193	51.44%	99.3	0.0	3,572.7	97.3%	90%	10,952	144.6	28.57%	47.00%	0.300	0.223
Coleman Unit 2	202	45.70%	92.3	0.0	3,579.7	97.5%	90%	10,515	145.0	32.24%	47.00%	0.290	0.227
Coleman Unit 3	184	35.07%	64.5	0.0	3,607.5	98.2%	90%	10,589	150.0	29.50%	47.00%	0.294	0.221
HMPL Unit 1	589	42.28%	249.0	0.0	3,423.0	93.2%	90%	10,411	152.2	88.40%	90.00%	0.053	0.046
HMPL Unit 2	413	32.01%	132.2	0.0	3,539.8	96.4%	90%	10,641	158.2	90.38%	90.00%	0.046	0.048
Green Unit 1	220	60.22%	132.5	0.0	3,539.5	96.4%	90%	10,518	231.0	50.49%	50.00%	0.204	0.206
Green Unit 2	88	39.20%	34.5	0.0	3,637.5	99.1%	90%	10,539	223.0	51.90%	50.00%	0.203	0.211
Wilson Unit	694	44.87%	311.4	0.0	3,360.6	91.5%	90%	10,348	416.8	90.72%	90.00%	0.040	0.043
Reid Unit 1	457	36.16%	165.3	1,502.8[5]	2,003.9	54.6%	85%	11,867	65.0	59.24%	81.71%	0.331	0.149
Reid CT	0	0.00%	0.0	3,672.0[6]	0.0	0.0%	85%	13,347	65.0	83.15%	83.15%	0.150	0.150

Notes:

(1) Annual forced outage hours from the BREC Production Cost Report dated 01-11-06.

(2) Expressed as a percentage of the total annual forced outage hours. Refer to Appendix H.

(3) Annual forced outage hours times the 2000-05 average OTAG season forced outage hours percent.

(4) No planned outages are projected for the OTAG season for the Wilson, Coleman, HMPL, or Green units.

(5) Reserve standby hours are projected for Reid Unit 1 using a 54.6 percent unit availability factor. The 54.6 percent availability factor is based on 2005 actual generation data provided by WKE. Refer to Appendix H.

(6) The Reid CT availability was assumed to be zero during the 2008 OTAG season.

(7) The OTAG season total hours of 3672 less the OTAG season forced outage hours and planned outage hours.

(8) The OTAG season available hours as a percent of the OTAG season total hours.

(9) Based on the same capacity factors as WKE Plan 8A spreadsheet. Refer to Appendix E.

(10) Net heat rates from the BREC Production Cost Report dated 01-11-06.

(11) Rated for the OTAG season. Capacities are from the "BREC Steam and Combustion Generating Unit Data" spreadsheet dated January 2006.

(12) Removal efficiencies based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE.

(13) Assumed removal efficiencies provided in WKE Plan 8A spreadsheet. Refer to Appendix E.

(14) Actual emission rates are based on the average of the actual 2004 and 2005 emission rates from the "04 05 Ozone Season Emission Rates.xls" spreadsheet provided by WKE. Emission rates exclusive of SCR events were used for HMPL Units 1 and 2 and the Wilson Unit.

(15) Assumed emission rates provided in WKE Plan 8A spreadsheet. Refer to Appendix E.

Forced Outages

The number of forced outage hours which occurred from 2000 through 2005 by unit are documented in Appendix H. The outages occurring during the May 1 through September 30 period of time (OTAG season) were determined and summarized. The HMPL Unit 1 boiler event which occurred on August 23, 2004 and lasted 515 hours was removed from the analysis of availability during the OTAG season due to the catastrophic nature of the event and the unlikely occurrence of a repeat event.

Number of Starts

The number of unit starts per unit was determined based on a review of historical forced outages for the years 2000 through 2005 for the months of May through September. The number of unit starts per unit and the hours per unit start are documented in Appendix H for the years 2000 through 2005.

The OTAG season (May 1 through September 30) historical forced outage hours were averaged for the years 2000 through 2005. The OTAG season historical unit starts were also averaged per unit for the years 2000 through 2005. An average number of forced outage hours and unit starts were determined for each unit from this data.

Sensitivity Cases

The availability, capacity factors, and heat rates for Sensitivity Cases 1 and 2 are presented below.

Availability

Sensitivity Case 1 consisted of a reduction in the availability for each unit to a value 50 percent lower than the 2007 and 2008 Base Case OTAG season hours. The generation from the unit that had the reduced availability was distributed to the other units. The total OTAG season system generated energy was held constant. The following parameters were used:

1. When one of the Coleman units was reduced an additional 50 percent of their Base Case availability, the following unit dispatch priority was used:
    a. The HMPL Units 1 and 2 were loaded up to 100 percent capacity factor.
    b. The Wilson Unit was loaded up to 100 percent capacity factor.
    c. The other Coleman units were loaded up to 100 percent capacity factor until the total system energy was satisfied.
2. When one of the HMPL units was reduced an additional 50 percent of their Base Case availability, the following priority was used:
    a. The other HMPL unit was loaded up to 100 percent capacity factor.

   b. The Wilson Unit was loaded up to 100 percent capacity factor.

   c. The Coleman units were loaded up to 100 percent capacity factor until the total system energy was satisfied.

3. When one of the Green units was reduced an additional 50 percent of their Base Case availability, the following priority was used:

   a. HMPL Units 1 and 2 were loaded up to 100 percent capacity factor.

   b. The Wilson Unit was loaded up to 100 percent capacity factor.

   c. The Coleman units were loaded up to 100 percent capacity factor until the total system energy was satisfied.

4. When the Wilson unit was reduced an additional 50 percent of its Base Case availability, the following priority was used:

   a. The HMPL Units 1 and 2 were loaded up to 100 percent capacity factor.

   b. The Coleman units were loaded up to 100 percent capacity factor.

   c. The Green units were loaded up to 100 percent capacity factor.

   d. The Reid Unit 1 was loaded up to 100 percent capacity factor.

   e. The Reid CT was utilized to generate the additional energy to satisfy the total system energy.

5. When the Reid Unit 1 was reduced an additional 50 percent of its Base Case availability, the following priority was used:

   a. HMPL Unit 1 was loaded up to 100 percent capacity factor.

   b. HMPL Unit 2 was then loaded until the total system energy was satisfied.

Availability factors used in Sensitivity Cases 1 and 2 are depicted below in Table 5-5.

Table 5-5 Sensitivity Cases 1 & 2 Availability Factors

Unit	Sensitivity Case 1(1)		Sensitivity Case 2(2)	
	2007	2008	2007	2008
Coleman Unit 1	48.65%	48.65%	97.30%	97.30%
Coleman Unit 2	48.69%	48.74%	97.39%	97.49%
Coleman Unit 3	49.12%	49.12%	98.24%	98.24%
HMPL Unit 1	45.87%	46.61%	91.73%	93.22%
HMPL Unit 2	47.90%	48.20%	95.80%	96.40%
Green Unit 1	48.06%	48.20%	96.11%	96.39%
Green Unit 2	49.72%	49.53%	99.43%	99.06%
Wilson Unit	44.70%	45.76%	89.41%	91.52%
Reid Unit 1	27.29%	27.29%	54.57%	54.57%
Reid CT	0.00%	0.00%	0.00%	0.00%

Notes:

(1) Sensitivity Case 1 availability factors document each unit at 50 percent of the Base Case availability factors that are noted in Tables 5-3 and 5-4.

(2) Sensitivity Case 2 uses the same availability factors as the Base Case availability factors noted in Tables 5-3 and 5-4.

Capacity Factor

Sensitivity Case 1 capacity factors vary by 36 individual scenario runs, depending upon which unit was reduced an additional 50 percent of its Base Case availability. When the Wilson Unit availability was reduced to 50 percent of its Base Case availability (Sensitivity Case S1h), all eight of the other units plus the Reid CT were needed to achieve the Base Case system generation. The generation from the other eight units and the Reid CT was determined using a 100 percent capacity factor. A comparison of the Sensitivity Cases 1 and 2 capacity factors are documented in Tables 5-6 and 5-7 for 2007 and 2008, respectively.

Table 5-6 Sensitivity Cases 1 & 2 2007 Capacity Factors

Unit	Sensitivity Case 1									Sensitivity Case 2
	Coleman Unit 1 Sensitivity Case S1a	Coleman Unit 2 Sensitivity Case S1b	Coleman Unit 3 Sensitivity Case S1c	HMPL Unit 1 Sensitivity Case S1d	HMPL Unit 2 Sensitivity Case S1e	Green Unit 1 Sensitivity Case S1f	Green Unit 2 Sensitivity Case S1g	Wilson Unit Sensitivity Case S1h	Reid Unit 1 Sensitivity Case S1i	
Coleman Unit 1	90.00%	90.00%	89.13%	96.58%	100.00%	100.00%	100.00%	100.00%	90.00%	90.00%
Coleman Unit 2	90.00%	90.00%	90.00%	90.00%	91.24%	100.00%	100.00%	100.00%	90.00%	90.00%
Coleman Unit 3	90.00%	90.00%	90.00%	90.00%	90.00%	92.84%	92.75%	100.00%	90.00%	90.00%
HMPL Unit 1	100.00%	100.00%	100.00%	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%	90.00%
HMPL Unit 2	100.00%	100.00%	100.00%	100.00%	90.00%	100.00%	100.00%	100.00%	89.97%	90.00%
Green Unit 1	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	100.00%	90.00%	90.00%
Green Unit 2	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	100.00%	90.00%	90.00%
Wilson Unit	98.87%	98.93%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	90.00%	90.00%
Reid Unit 1	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	100.00%	85.00%	85.00%
Reid CT	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%

Table 5-7 Sensitivity Cases 1 & 2 2008 Capacity Factors

Unit	Sensitivity Case 1									Sensitivity Case 2
	Coleman Unit 1 Sensitivity Case S1a	Coleman Unit 2 Sensitivity Case S1b	Coleman Unit 3 Sensitivity Case S1c	HMPL Unit 1 Sensitivity Case S1d	HMPL Unit 2 Sensitivity Case S1e	Green Unit 1 Sensitivity Case S1f	Green Unit 2 Sensitivity Case S1g	Wilson Unit Sensitivity Case S1h	Reid Unit 1 Sensitivity Case S1i	
Coleman Unit 1	90.00%	90.00%	90.00%	96.60%	100.00%	100.00%	100.00%	100.00%	90.00%	90.00%
Coleman Unit 2	90.00%	90.00%	90.00%	90.00%	90.75%	100.00%	100.00%	100.00%	90.00%	90.00%
Coleman Unit 3	90.00%	90.00%	90.00%	90.00%	90.00%	92.21%	91.67%	100.00%	90.00%	90.00%
HMPL Unit 1	100.00%	100.00%	100.00%	90.00%	100.00%	100.00%	100.00%	100.00%	100.00%	90.00%
HMPL Unit 2	100.00%	100.00%	100.00%	100.00%	90.00%	100.00%	100.00%	100.00%	89.82%	90.00%
Green Unit 1	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	100.00%	90.00%	90.00%
Green Unit 2	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	100.00%	90.00%	90.00%
Wilson Unit	98.58%	98.65%	99.36%	100.00%	100.00%	100.00%	100.00%	100.00%	90.00%	90.00%
Reid Unit 1	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	100.00%	85.00%	85.00%
Reid CT	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%	85.00%

Heat Rate

Sensitivity Case 1 model runs utilized heat rates from the BREC Production Cost Report dated 01-11-06. Sensitivity Case 2 model runs were made for each unit with its heat rate increased by 400 Btu/kWh from the BREC Production Cost Report heat rates for the OTAG seasons of 2007 and 2008. Sensitivity Case 2 consisted of increasing the heat rate for each unit to account for condenser fouling, air heater pluggage, or other operational impacts. The net heat rate used in Sensitivity Cases 1 and 2 is depicted below in Table 5-8.

Table 5-8 Sensitivity Cases 1 & 2 Heat Rates (Btu/kWh)

Unit	Sensitivity Case 1 (1)		Sensitivity Case 2 (2)	
	2007	2008	2007	2008
Coleman Unit 1	10,984	10,952	11,384	11,352
Coleman Unit 2	10,755	10,515	11,155	10,915
Coleman Unit 3	10,582	10,589	10,982	10989
HMPL Unit 1	10,570	10,411	10,970	10,811
HMPL Unit 2	10,743	10,641	11,143	11,041
Green Unit 1	10,509	10,518	10,909	10,918
Green Unit 2	10,531	10,539	10,931	10,939
Wilson Unit	10,824	10,348	11,224	10,748
Reid Unit 1	11,869	11,867	12,269	12,267

Notes:
(1) Values derived from BREC Production Cost Report dated 01-11-06.
(2) Sensitivity Case 2 model runs were based on each unit's heat rate increased by 400 Btu/kWh from the Base Case heat rates derived from the BREC Production Cost Report dated 01-11-06.

Projected 2007 and 2008 Additional NO_x Event Tons

The additional projected 2007 and 2008 NO_x emissions are based on the spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Model.xls" presented in the January 5, 2006, WKE NO_x Compliance Review meeting. This spreadsheet documented events during which additional tons of NO_x emissions were generated during the 2004 and 2005 OTAG seasons. Based on the data presented, the WKE Plan 8A does not allow for sufficient variations for equipment failure events, forced outage events, or additional generation. Section 2 of this report discusses the additional emissions documented in the "04 and 05 Organized Data from WKE NO_x Model.xls" spreadsheet.

The projected additional NO_x emissions due to events for 2007 and 2008 are depicted in Table 5-9.

Table 5-9 2007 & 2008 OTAG Season - Additional NO_x Emissions

Unit	Description	Average 2004-05 Hours	Average 2004-05 Emission Rate (Tons/Hour)	Average 2004-05 Emissions (Tons)
Coleman Unit 1	Additional emissions due to CEM heat input data	---	---	46.56(3)
Coleman Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	-12.17(3)
Coleman Unit 1 Total				**34.39**
Coleman Unit 2	Additional emissions due to CEM heat input data	---	---	19.30(3)
Coleman Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	-1.36(3)
Coleman Unit 2 Total		---	---	**17.94**
Coleman Unit 3	Additional emissions due to CEM heat input data	---	---	66.28(3)
Coleman Unit 3	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	-24.02(3)
Coleman Unit 3 Total				**42.26**
HMPL Unit 1	SCR off due to application of coal drying agent	---	---	33.78(3)
HMPL Unit 1	SCR warm up events from forced outages	68.50(1)	0.321375(1)	22.01
HMPL Unit 1	SCR load reduction due to low temperature events	---	---	5.28 (3)
HMPL Unit 1	Due to operation of the SCR in the bypass mode (Max. Potential Emissions)	---	---	10.66 (3)
HMPL Unit 1	Additional emissions due to CEM heat input delta	---	---	13.65(3)
HMPL Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	-8.46(3)
HMPL Unit 1	Additional emissions due to NO_x analyzer issues	---	---	9.89(3)
HMPL Unit 1 Total				**86.81**
HMPL Unit 2	SCR off due to application of coal drying agent	---	---	43.69(3)
HMPL Unit 2	SCR warm up events from forced outages	52.50(1)	0.3977145(1)	20.88
HMPL Unit 2	SCR load reduction due to low temperature events	---	---	8.21(3)
HMPL Unit 2	Due to operation with the SCR in bypass (Max Potential Emissions)	---	---	14.16(3)

Table 5-9 2007 & 2008 OTAG Season - Additional NO_x Emissions (Continued)

Unit	Description	Average 2004-05 Hours	Average 2004-05 Emission Rate (Tons/Hour)	Average 2004-05 Emissions (Tons)
HMPL Unit 2	Due to Cal failure event	---	---	10.41(3)
HMPL Unit 2	Additional emissions due to CEM heat input delta	---	---	27.91(3)
HMPL Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	-1.55(3)
HMPL Unit 2	Additional emissions due to NO_x analyzer issues	---	---	4.94(3)
HMPL Unit 2 Total		---	---	**128.65**
Green Unit 1	Additional emissions due to CEM heat input data	---	---	-12.70(3)
Green Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	18.15(3)
Green Unit 1 Total		---	---	**5.45**
Green Unit 2	Additional emissions due to CEM heat input data	---	---	20.39(3)
Green Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	21.25(3)
Green Unit 2 Total		---	---	**41.64**
Wilson Unit	SCR warm up after outages	99.00(1)	0.7256205(1)	71.84
Wilson Unit	Additional emissions due to #3 Mill operation	1,208.75(2)	0.0925455(1)	111.87
Wilson Unit	Additional emissions due to CEM heat input	---	---	29.11(3)
Wilson Unit	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	3.83(3)
Wilson Unit Total		---	---	**216.65**
Reid Unit 1	Additional emissions due to CEM heat input data	---	---	25.88(3)
Reid Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	---	---	5.98(3)
Reid Unit 1 Total		---	---	**31.86**
SYSTEM TOTAL		---	---	**605.65**

Notes:

(1) Based on an average of the 2004 and 2005 emission rates (tons per hour) from the "04 and 05 Organized Data from WKE NO_x Model.xls" spreadsheet.

(2) Based on the 2004 number of hours with Mill #3 in operation from the "04 and 05 Organized Data from WKE NO_x Model.xls" spreadsheet.

(3) Based on an average of the 2004 and 2005 tons of emissions from the "04 and 05 Organized Data from WKE NO_x Model.xls" spreadsheet.

Expected WKE Plan 8A Performance

2007 & 2008 Performance

Stanley Consultants evaluated the WKE Plan 8A to determine if the plan would allow the BREC system to "take care of itself" during the 2007 and 2008 OTAG season under a range of operating scenarios. Stanley Consultants analyzed the current system performance and provided a projection based on the current WKE Plan 8A and the BREC 2007-2010 Budget Work Plan.

All operating scenarios were modeled separately utilizing the average of the actual 2004-2005 emission rates and WKE Plan 8A assumed emission rates. Models utilizing the WKE Plan 8A assumed emission rates result in lower NO_x emissions. The actual emission rate values result in a higher NO_x emission for the OTAG season. For this reason, the results presented in this section are all based on the models utilizing actual emission rates. As an example, Reid Unit 1 WKE Plan 8A assumed emission rate was 0.149 lb/mmBtu (81.71 percent removal efficiency) and Reid Unit 1 actual emission rate 0.331 lb/mmBtu (59.24 percent removal efficiency).

A 100 percent availability case was developed for the 2007 and 2008 OTAG seasons to determine the WKE Plan 8A performance in a "perfect world" scenario. Table 5-10 documents the results of the 100 percent availability case using projected 2007 and 2008 OTAG season performance using actual emission rates and the additional projected amount of tons of NO_x due to events listed in Table 5-9, with the exception of SCR warm up events caused by forced outage conditions. With all units at 100 percent availability additional NO_x allowances are needed. It is not realistic to assume that all the units will be 100 percent available during the OTAG season. Therefore, the balance of this section will discuss the Base Case results.

- The 2007 OTAG season modeled NO_x tons indicates 79.6 tons of NO_x allowances would be needed, however, when the 2007 additional NO_x events are added to the WKE Plan 8A total NO_x tons, the results indicate that 570.5 NO_x allowances are needed.

- The 2008 OTAG season modeled NO_x tons indicates 45.9 tons of NO_x allowances would be needed, however, when the 2008 additional NO_x events are added to the WKE Plan 8A total NO_x tons, the results indicates that 536.8 NO_x allowances are needed.

Table 5-10 100% Availability Case 2007 & 2008 OTAG Season Evaluation

Unit	2007 OTAG Season Evaluation			2008 OTAG Season Evaluation		
	2007 Plan 8A NO$_x$ Tons	2007 Additional NO$_x$ Events Tons$^{(1)}$	2007 Total NO$_x$ Tons$^{(2)}$	2008 Plan 8A NO$_x$ Tons$^{(3)}$	2008 Additional NO$_x$ Events Tons$^{(1)}$	2008 Total NO$_x$ Tons$^{(3)}$
Coleman Unit 1	787.4	34.4	821.8	785.0	34.4	819.4
Coleman Unit 2	747.3	17.9	765.2	730.6	17.9	748.5
Coleman Unit 3	771.1	42.3	813.4	771.6	42.3	813.9
HMPL Unit 1	140.9	64.8$^{(4)}$	205.7	138.8	64.8$^{(4)}$	203.6
HMPL Unit 2	129.2	107.8$^{(4)}$	237.0	128.0	107.8$^{(4)}$	235.8
Green Unit 1	818.3	5.4	823.7	819.0	5.4	824.4
Green Unit 2	787.7	41.6	829.3	788.3	41.6	829.9
Wilson Unit	298.2	144.8$^{(4)}$	443.0	285.1	144.8$^{(4)}$	429.9
Reid Unit 1	398.5	31.9	430.4	398.5	31.9	430.4
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,878.6	490.9	5,369.5	4,844.9	490.9	5,335.8
Excess NO$_x$ Allowances (Tons)	---	---	---	---	---	---
Additional NO$_x$ Allowances Needed (Tons)	79.6	---	570.5	45.9	---	536.8
Allocated NO$_x$ Allowances	4,799	---	4,799	4,799	---	4,799

Notes:

(1) Refer to Appendix D for a description of the events that resulted in additional tons of NO$_x$. WKE additional NO$_x$ events tons were projected for 2007 and 2008 based on information from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO$_x$ Models.xls" The projections are presented in Section 5.

(2) This is a calculated value from the sum of "2007 Plan 8A NO$_x$ Tons" column and "2007 Additional NO$_x$ Events Tons" column.

(3) This is a calculated value from the sum of "2008 Plan 8A NO$_x$ Tons" column and "2008 Additional NO$_x$ Events Tons" column.

(4) SCR warm up events due to forced outages are subtracted from the projected 2007 and 2008 additional tons of NO$_x$ due to events total.

A base case was developed for the 2007 and 2008 OTAG seasons. Table 5-11 documents the results of the projected 2007 and 2008 OTAG season performance using actual emission rates and the additional projected amount of tons of NO$_x$ due to forced outage events, SCR warm up events, and other generation events.

- The 2007 OTAG season modeled NO$_x$ tons indicates an excess of 240.7 tons of NO$_x$ allowances would be available, however, when the 2007 additional NO$_x$ events are added to the WKE Plan 8A total NO$_x$ tons, the results indicate that 365 NO$_x$ allowances are needed.

- The 2008 OTAG season modeled NO$_x$ tons indicates an excess of 263.4 tons of NO$_x$ allowances would be available, however when the 2008 additional NO$_x$ events are added to the WKE Plan 8A total NO$_x$ tons, the results indicates that 342.3 NO$_x$ allowances are needed.

Table 5-11 Base Case Plan 8A 2007 & 2008 OTAG Season Evaluation

Unit	2007 OTAG Season Evaluation			2008 OTAG Season Evaluation		
	2007 Base Case Plan 8A NO_x Tons	2007 Additional NO_x Events Tons(1)	Base Case 2007 Total NO_x Tons(2)	2008 Base Case Plan 8A NO_x Tons	2008 Additional NO_x Events Tons(1)	Base Case 2008 Total NO_x Tons(3)
Coleman Unit 1	766.1	34.4	800.5	763.8	34.4	798.2
Coleman Unit 2	727.8	17.9	745.7	712.3	17.9	730.2
Coleman Unit 3	757.6	42.3	799.9	758.1	42.3	800.4
HMPL Unit 1	129.2	86.8	216.0	129.4	86.8	216.2
HMPL Unit 2	123.7	128.6	252.3	123.3	128.6	252.0
Green Unit 1	786.5	5.5	792.0	789.5	5.5	794.9
Green Unit 2	783.3	41.6	824.9	780.9	41.6	822.5
Wilson Unit	266.6	216.7	483.3	260.9	216.7	477.6
Reid Unit 1	217.5	31.9	249.4	217.4	31.9	249.3
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,558.3	605.7	5,164.0	4,535.6	605.7	5,141.3
Excess NO_x Allowances (Tons)	240.7	---	---	263.4	---	---
Additional NO_x Allowances Needed (Tons)	---	---	365.0	---	---	342.3
Allocated NO_x Allowances	4,799	---	4,799	4,799	---	4,799

Notes:

(1) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were projected for 2007 and 2008 based on information from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls."

(2) This is a calculated value from the sum of "2007 Base Case Plan 8A NO_x Tons" column and "2007 Additional NO_x Events Tons" column.

(3) This is a calculated value from the sum of "2008 Base Case Plan 8A NO_x Tons" column and "2008 Additional NO_x Events Tons" column.

Impacts Due to Sensitivity Analysis

Sensitivity Cases

Two sensitivity case scenarios were developed to test the impact of certain parameters after the Base Case parameters were developed. Sensitivity analyses were performed to aid in the identification of future operational exposures by applying different unit specific heat rates and capacity factors.

Sensitivity Case 1

Sensitivity Case 1 consisted of a reduction in the availability for each unit to a value 50 percent lower than the 2007 and 2008 Base Case OTAG season hours. The energy requirement from the unit with the reduced availability was distributed to the other units in the BREC system. The 2007 results are noted as follows:

- The Wilson Unit Sensitivity Case S1h, which is the most severely impacted, results in the worst case with an additional 324.9 NO_x allowances needed. If the additional estimated system NO_x event tons (605.6 tons minus 216.6 or 389.0 tons) due to operational events is added to the modeled number, 713.9 additional NO_x allowances are needed, indicating that the WKE Plan 8A will not satisfy the BREC system requirements.

- Sensitivity Cases S1a through S1g and S1i ranged from 163.5 excess NO_x allowances to 569.4 tons of excess NO_x allowances. If the additional estimated system NO_x event tons due to operational events are added to these results, it ranges from an excess of 5.8 tons of NO_x allowances to additional allowances needed of 313.5 tons.

- If the availability of one of the units equipped with SCRs (either HMPL Unit 1, HMPL Unit 2, or the Wilson Unit) is reduced, the additional kWh generation may need to be produced from units which are not equipped with SCRs. In that case, the overall tons of emissions are increased to satisfy the BREC system generation needs. The additional NO_x allowances that may be needed indicate that the WKE Plan 8A will not satisfy the BREC system requirements.

The results for 2008 are noted as follows:

- The Wilson Unit Sensitivity Case S1h results in the worst case with an additional 316.6 NO_x allowances needed. If the additional estimated system NO_x event tons (605.6 tons minus 216.6 or 389.0 tons) due to operational events is added to the modeled number, 705.6 additional NO_x allowances are needed, indicating that the WKE Plan 8A will not satisfy the BREC system requirements.

- Sensitivity Cases S1a through S1g and S1i ranged from 190.9 excess NO_x allowances to 592.4 tons of excess NO_x allowances. If the additional estimated system NO_x event tons due to operational events are added to these results, it ranges from an excess of 23.8 tons of NO_x allowances to additional allowances needed of 289.5 tons.

Tables 5-12 and 5-13 documents the comparison of the 2007 and 2008 Base Case controlled tons of NO_x to the sensitivity cases performed for each unit at reduced capacity factors.

Table 5-12 2007 Base Case Versus Sensitivity Case 1

Unit	Base Case Plan 8A NO_x Tons[1]	Coleman Unit 1 Sensitivity Case S1a	Coleman Unit 2 Sensitivity Case S1b	Coleman Unit 3 Sensitivity Case S1c	HMPL Unit 1 Sensitivity Case S1d	HMPL Unit 2 Sensitivity Case S1e	Green Unit 1 Sensitivity Case S1f	Green Unit 2 Sensitivity Case S1g	Wilson Unit Sensitivity Case S1h	Reid Unit 1 Sensitivity Case S1i
Coleman Unit 1	766.1	383.0	766.0	758.6	822.0	851.2	851.2	851.2	851.2	766.0
Coleman Unit 2	727.8	727.8	363.9	727.8	727.8	737.8	808.6	808.6	808.6	727.8
Coleman Unit 3	757.6	757.6	757.6	378.8	757.6	757.5	781.4	780.7	841.8	757.6
HMPL Unit 1	129.2	143.6	143.6	143.6	64.6	143.6	143.6	143.6	143.6	143.6
HMPL Unit 2	123.7	137.5	137.5	137.5	137.5	61.9	137.5	137.5	137.5	123.7
Green Unit 1	786.5	786.5	786.5	786.5	786.5	786.5	393.3	786.5	873.9	786.5
Green Unit 2	783.3	783.3	783.3	783.3	783.3	783.3	783.3	391.7	870.3	783.3
Wilson Unit	266.6	292.8	293.0	296.2	296.2	296.2	296.2	296.2	148.1	266.6
Reid Unit 1	217.5	217.5	217.5	217.5	217.5	217.5	217.5	217.5	443.8	108.7
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	0.0
Total Modeled Tons	4,558.3	4,229.6	4,248.9	4,229.8	4,593.0	4,635.5	4,412.6	4,413.5	5,123.9	4,463.8
Excess NO_x Allowances (Tons)[4]	240.7	569.4	550.1	569.2	206.0	163.5	386.4	385.5	---	335.2
NO_x Allowances Needed (Tons)[4]	---	---	---	---	---	---	---	---	324.9	---
Additional System NO_x Events Tons[3]	605.6	571.2	587.7	563.4	518.8	477.0	600.2	564.0	389.0	573.8
TOTAL	5,163.9	4,800.8	4,836.6	4,793.2	5,111.8	5,112.5	5,012.8	4,977.5	5,512.9	5,037.6
Total Excess NO_x Allowances (Tons)[4]	---	---	---	5.8	---	---	---	---	---	---
Total NO_x Allowances Needed (Tons)[4]	364.9	1.8	37.6	---	312.8	313.5	213.8	178.5	713.9	238.6

Notes:

(1) Values were calculated in the 2007 Base Case OTAG season evaluation.

(2) Refer to Table 5-9 for the Base Case 2007 and 2008 OTAG Season – Additional NO_x Emissions.

(3) A conservative approach to additional system NO_x operational event emissions was used. The values range from the averaged 2004 and 2005 data to the maximum tons (605.6 tons) reported by WKE in the spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls".

(4) Based on allocated NO_x allowances of 4,799 tons.

Table 5-13 2008 Base Case Versus Sensitivity Case 1

Unit	Base Case Plan 8A NO_x Tons [1]	Coleman Unit 1 Sensitivity Case S1a	Coleman Unit 2 Sensitivity Case S1b	Coleman Unit 3 Sensitivity Case S1c	HMPL Unit 1 Sensitivity Case S1d	HMPL Unit 2 Sensitivity Case S1e	Green Unit 1 Sensitivity Case S1f	Green Unit 2 Sensitivity Case S1g	Wilson Unit Sensitivity Case S1h	Reid Unit 1 Sensitivity Case S1i
Coleman Unit 1	763.8	381.9	763.8	763.8	819.9	848.7	848.7	848.7	848.7	763.8
Coleman Unit 2	712.3	712.2	356.1	712.3	712.3	718.2	791.4	791.4	791.4	712.3
Coleman Unit 3	758.1	758.1	758.1	379.0	758.1	758.1	776.7	772.1	842.3	758.1
HMPL Unit 1	129.4	143.7	143.7	143.7	64.7	143.7	143.7	143.7	143.7	143.7
HMPL Unit 2	123.3	137.1	137.1	137.1	137.1	61.7	137.1	137.1	137.1	123.1
Green Unit 1	789.5	789.5	789.5	789.5	789.5	789.5	394.7	789.5	877.2	789.5
Green Unit 2	780.9	780.9	780.9	780.9	780.9	780.9	780.9	390.5	867.7	780.9
Wilson Unit	260.9	285.8	286.0	288.0	289.9	289.9	289.9	289.9	144.9	260.9
Reid Unit 1	217.4	217.4	217.4	217.5	217.4	217.4	217.4	217.4	447.7	108.7
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.9	0.0
Total Modeled Tons	4,535.6	4,206.6	4,232.6	4,211.8	4,569.7	4,608.1	4,380.5	4,380.3	5,115.6	4,441.0
Excess NO_x Allowances (Tons)[4]	263.4	592.4	566.4	587.2	229.3	190.9	418.5	418.7	---	358.0
NO_x Allowances Needed (Tons)[4]	---	---	---	---	---	---	---	---	316.6	---
Additional System NO_x Events Tons[3]	605.6	571.2	587.7	563.4	518.8	477.0	600.2	564.0	389.0	573.8
TOTAL	5,141.2	4,777.8	4,820.3	4,775.2	5,088.5	5,085.1	4,980.7	4,944.3	5,504.6	5,014.8
Total Excess NO_x Allowances (Tons)[4]	---	21.2	---	23.8	---	---	---	---	---	---
Total NO_x Allowances Needed (Tons)[4]	342.2	---	21.3	---	289.5	286.1	181.7	145.3	705.6	215.8

Notes:

(1) Values were calculated in the 2008 OTAG season evaluation.

(2) Refer to Table 5-9 for the Base Case 2007 and 2008 OTAG Season – Additional NO_x Emissions.

(3) A conservative approach to additional system NO_x operational event emissions was used. The values range from the averaged 2004 and 2005 data to the maximum tons (605.6 tons) reported by WKE in the spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls".

(4) Based on allocated NO_x allowances of 4,799 tons.

Sensitivity Case 2

Sensitivity Case 2 consisted of increasing the heat rate for each unit by 400 Btu/kWh to account for condenser fouling, air heater pluggage, or other operational impacts. The results for 2007 are noted as follows:

- The results for the 2007 Sensitivity Cases S2a through S2i did not exceed the Wilson Unit Sensitivity Case S1h results (worst case resulting in an additional 324.9 NO_x allowances needed). Sensitivity Cases S2a through S2i ranged from 210.8 excess NO_x allowances to 236.1 tons of excess NO_x allowances. If the additional estimated system NO_x event tons (605.6 tons) due to operational events are added to these results, the range of additional allowances needed are 369.5 to 394.8, indicating that the WKE Plan 8A will not satisfy the BREC system requirements.

- The specific unit with the increased heat rate results in a higher number of tons being produced when compared with the Base Case. For example, if the Wilson Unit heat rate is increased by 400 Btu/kWh, the tons of emissions are 276.4 tons in Sensitivity Case S2h while in the Base Case the Wilson Unit produced 266.6 tons of emissions.

Results for the 2008 Sensitivity Cases S2a through S2i are presented below.

- The results for the 2008 Sensitivity Cases S2a through S2i did not exceed the Wilson Unit Sensitivity Case S1h results (worst case resulting in an additional 316.6 NO_x allowances needed). Sensitivity Cases S2a through S2i ranged from 233.4 excess NO_x allowances to 258.8 tons of excess NO_x allowances. If the additional estimated system NO_x event tons (605.6 tons) due to operational events are added to these results, the range of additional allowances needed are 346.8 to 372.2, further indicating that the WKE Plan 8A will not satisfy the BREC system requirements.

Tables 5-14 and 5-15 documents the comparison of the 2007 and 2008 Base Case Plan 8A controlled tons of NO_x to the sensitivity cases performed for each unit at an increased heat rate.

Table 5-14 2007 Base Case Versus Sensitivity Case 2

Unit	Base Case Plan 8A NO_x Tons [1]	Coleman Unit 1 Sensitivity Case S2a	Coleman Unit 2 Sensitivity Case S2b	Coleman Unit 3 Sensitivity Case S2c	HMPL Unit 1 Sensitivity Case S2d	HMPL Unit 2 Sensitivity Case S2e	Green Unit 1 Sensitivity Case S2f	Green Unit 2 Sensitivity Case S2g	Wilson Unit Sensitivity Case S2h	Reid Unit 1 Sensitivity Case S2i
Coleman Unit 1	766.1	794.0	766.1	766.1	766.1	766.1	766.1	766.1	766.1	766.1
Coleman Unit 2	727.8	727.8	754.8	727.8	727.8	727.8	727.8	727.8	727.8	727.8
Coleman Unit 3	757.6	757.6	757.6	786.2	757.6	757.6	757.6	757.6	757.6	757.6
HMPL Unit 1	129.2	129.2	129.2	129.2	134.1	129.2	129.2	129.2	129.2	129.2
HMPL Unit 2	123.7	123.7	123.7	123.7	123.7	128.3	123.7	123.7	123.7	123.7
Green Unit 1	786.5	786.5	786.5	786.5	786.5	786.5	816.4	786.5	786.5	786.5
Green Unit 2	783.3	783.3	783.3	783.3	783.3	783.3	783.3	813.0	783.3	783.3
Wilson Unit	266.6	266.6	266.6	266.6	266.6	266.6	266.6	266.6	276.4	266.6
Reid Unit 1	217.5	217.5	217.5	217.5	217.5	217.5	217.5	217.5	217.5	224.8
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Modeled Tons	4,558.3	4,586.2	4,585.3	4,586.9	4,563.2	4,562.9	4,588.2	4,588.0	4,568.1	4,565.6
Excess NO_x Allowances (Tons)[3]	240.7	212.8	213.7	212.1	235.8	236.1	210.8	211.0	230.9	233.4
NO_x Allowances Needed (Tons)[3]	---	---	---	---	---	---	---	---	---	---
Additional System NO_x Events Tons[2]	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6
TOTAL	5,163.9	5,191.8	5,190.9	5,192.5	5,168.8	5,168.5	5,193.8	5,193.6	5,173.7	5,171.2
Total NO_x Allowances Needed (Tons)[3]	364.9	392.8	391.9	393.5	369.8	369.5	394.8	394.6	374.7	372.2

Notes:

(1) Values were calculated in the 2007 Base Case OTAG season evaluation.

(2) Refer to Table 5-9 for the Base Case 2007 and 2008 OTAG Season – Additional NO_x Emissions.

(3) Based on allocated NO_x allowances of 4,799 tons.

Table 5-15 2008 Base Case Versus Sensitivity Case 2

Unit	Base Case Plan 8A NO_x Tons [1]	Coleman Unit 1 Sensitivity Case S2a	Coleman Unit 2 Sensitivity Case S2b	Coleman Unit 3 Sensitivity Case S2c	HMPL Unit 1 Sensitivity Case S2d	HMPL Unit 2 Sensitivity Case S2e	Green Unit 1 Sensitivity Case S2f	Green Unit 2 Sensitivity Case S2g	Wilson Unit Sensitivity Case S2h	Reid Unit 1 Sensitivity Case S2i
Coleman Unit 1	763.8	791.7	763.8	763.8	763.8	763.8	763.8	763.8	763.8	763.8
Coleman Unit 2	712.3	712.3	739.3	712.3	712.3	712.3	712.3	712.3	712.3	712.3
Coleman Unit 3	758.1	758.1	758.1	786.7	758.1	758.1	758.1	758.1	758.1	758.1
HMPL Unit 1	129.4	129.4	129.4	129.4	134.3	129.3	129.4	129.3	129.4	129.3
HMPL Unit 2	123.3	123.3	123.4	123.3	123.4	128.0	123.3	123.3	123.3	123.3
Green Unit 1	789.5	789.5	789.5	789.5	789.5	789.5	819.5	789.5	789.5	789.5
Green Unit 2	780.9	780.9	780.9	780.9	780.9	780.9	780.9	810.6	780.9	780.9
Wilson Unit	260.9	260.9	260.9	260.9	260.9	260.9	260.9	260.9	271.0	260.9
Reid Unit 1	217.4	217.4	217.4	217.4	217.4	217.4	217.4	217.4	217.4	224.8
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Modeled Tons	4,535.6	4,563.5	4,562.7	4,564.2	4,540.6	4,540.2	4,565.6	4,565.2	4,545.7	4,542.9
Excess NO_x Allowances (Tons)[3]	263.4	235.5	236.3	234.8	258.4	258.8	233.4	233.8	253.3	256.1
NO_x Allowances Needed (Tons)[3]	---	---	---	---	---	---	---	---	---	---
Additional System NO_x Events Tons[2]	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6	605.6
TOTAL	5,141.2	5,169.1	5,168.3	5,169.8	5,146.2	5,145.8	5,171.2	5,170.8	5,151.3	5,148.5
Total NO_x Allowances Needed (Tons)[3]	342.2	370.1	369.3	370.8	347.2	346.8	372.2	371.8	352.3	349.5

Notes:
(1) Values were calculated in the 2008 Base Case OTAG season evaluation.
(2) Refer to Table 5-9 for the Base Case 2007 and 2008 OTAG Season – Additional NO_x Emissions.
(3) Based on allocated NO_x allowances of 4,799 tons.

Solutions to Impact

Heat Rate

Improvements to a specific unit heat rate can be accomplished by improved maintenance and operations practices and improving fuel quality. As shown in the Sensitivity Case 2 model runs increasing the unit heat rate by 400 Btu/kWh increases the tons of emissions. For example, Wilson Unit 2007 Base Case controlled tons of NO_x amount was 266.6 tons utilizing the projected heat rate from the BREC production cost model, when this heat rate was increased the Wilson 2007 Sensitivity Case 2h controlled tons of NO_x was 276.4 tons.

Forced Outages

Forced outages affect the availability of the units. The WKE Plan 8A assumed 100 percent availability for all the units. Identification of the components that have been the leading causes of the force outages would help focus resources toward those pieces of equipment that have the greatest potential for improvement.

The impact of historical forced outages on the tons of emissions generated by the individual units and the system was reviewed. The major contributor to forced outages for the BREC units is boiler tube leaks. The boiler tube leaks which occurred by unit during the 2004 and 2005 OTAG season are summarized in Tables 5-16 and 5-17, respectively. From Tables 5-16 and 5-17, it can be determined that boiler tube leaks forced the units off line:

- Coleman Unit 1 – 5 hours in 2004 and 177 hours in 2005
- Coleman Unit 2 – 77 hours in 2004 and 64 hours in 2005
- Coleman Unit 3 – 43 hours in 2004
- Green Unit 1 – 137 hours in 2004
- Green Unit 2 – 21 hours in 2005
- HMPL Unit 1 – 647 hours in 2004 (boiler water event) and 90 hours in 2005
- HMPL Unit 2 – 64 hours in 2004
- Reid Unit 1 – 65 hours in 2005
- Wilson Unit – 219 hours in 2004 and 178 hours in 2005

Table 5-16 Tube Leak Summary May through September 2004(1)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
COLEMAN UNIT 1:				
4/29/04	UO2	Tube leak in the reheat section of the boiler. Total outage was 48 hours 44 minutes	5	19
Coleman Unit 1 Total			**5**	**19**
COLEMAN UNIT 2:				
7/16/04	UO4	One tube leak in superheat section at 8L sootblower	28	43
9/28/04	UO4	Unit off to repair tube leak in the HRA section west side of boiler. Total outage was 57 hours 11 minutes.	48	28
Coleman Unit 2 Total			**77**	**11**
COLEMAN UNIT 3:				
6/20/04	UO1	Unit removed from service due to two tube leaks in economizer section of the boiler	43	26
Coleman Unit 3 Total			**43**	**26**
GREEN UNIT 1:				
6/13/04	UO2	Repair tube leak in reheat outlet section of boiler.	41	16
8/2/04	UO1	Waterwall tube leak	50	04
9/16/04	UOI	Waterwall tube leak	34	23
9/30/04	UO3	Reheater tube leak. Total outage was 41 hours 2 minutes.	11	46
Green Unit 1 Total			**137**	**29**
GREEN UNIT 2:				
None			**0**	**00**
HMPL UNIT 1:				
7/5/04	UO1	Waterwall tube leak.	72	59
8/21/04	UO1	Waterwall tube leak.	58	58
8/23/04	UO2	Waterwall tube leak.	515	17
HMPL Unit 1 Total			**647**	**14**
HMPL UNIT 2:				
5/17/04	UO2	Reheater tube leaks.	64	07
HMPL Unit 2 Total			**64**	**07**
REID UNIT 1:				
None			**0**	**00**

Table 5-16 Tube Leak Summary May through September 2004[1] (Continued)

Start Date	Class[2][3]	Description	Duration Hours	Duration Minutes
WILSON UNIT				
6/2/04	UO1	Tube leak on economizer inlet header tube.	42	00
6/15/04	UO1	Tube failure approx. 3 ft below IR-21.	61	07
8/25/04	UO1	Tube leak approx. 4 ft below IR-21.	57	50
9/27/04	UO1	Tube leaks on west wall and in knees.	58	07
Wilson Unit Total			**219**	**04**
SYSTEM TOTAL			**1,193**	**50**

Notes:

(1) OTAG Season.

(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), PMO (Planned Maintenance Outage), XPO/EPO (extended planned outage), UO4 (deferred), and RS (reserve shutdowns).

(3) Forced Outages (UO = Unplanned) include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed) and SF (start-up failure).

Table 5-17 Tube Leak Summary May through September 2005[1]

Start Date	Class[2][3]	Description	Duration Hours	Duration Minutes
COLEMAN UNIT 1:				
5/18/05	UO1	Unit trip tube leak in wet bottom area	49	23
7/9/05	UO2	Tube leak in wet bottom area of boiler	38	41
7/13/05	UO1	Tube leak in wet bottom area of boiler	89	38
Coleman Unit 1 Total			**177**	**42**
COLEMAN UNIT 2:				
9/25/05	UO4	Unit offline to repair wet bottom tube leak	32	03
9/29/05	UO2	Tube leak in convection superheater adjacent to 6R sootblower	32	31
Coleman Unit 2 Total			**64**	**34**
COLEMAN UNIT 3:				
None			**0**	**00**
GREEN UNIT 1:				
None			**0**	**00**
GREEN UNIT 2:				
5/25/05	UO2	Waterwall tube leak. Tube split open along overlay weld seam.	21	10
Green Unit 2 Total			**21**	**10**
HMPL UNIT 1:				
8/10/05	UO1	Unit tripped due to a water wall tube leak.	44	12
8/26/05	UO1	Unit tripped due to a water wall tube leak.	45	51
HMPL Unit 1 Total			**90**	**03**
HMPL UNIT 2:				
None			**0**	**00**

Table 5-17 Tube Leak Summary May 1 through September 2005[1] (Continued)

Start Date	Class[2][3]	Description	Duration Hours	Duration Minutes
REID UNIT 1:				
7/1/05	UO2	Waterwall tube leak above wet bottom, two economizer leaks and one in the wet bottom.	65	00
Reid Unit 1 Total			**65**	**00**
WILSON UNIT:				
8/2/05	UO1	Unit trip due to boiler tube leak.	36	18
8/9/05	UO1	Unit trip due to boiler tube leak.	30	22
8/10/05	UO1	Unit trip due to boiler tube leak.	66	37
8/24/05	UO1	Unit trip due to boiler tube leak.	45	29
Wilson Unit Total			**178**	**46**
SYSTEM TOTAL			**597**	**15**

Notes:
(1) OTAG Season.
(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), PMO (Planned Maintenance Outage), XPO/EPO (extended planned outage), UO4 (deferred), and RS (reserve shutdowns).
(3) Forced Outages (UO = Unplanned) include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed) and SF (start-up failure).

NO_x Removal Equipment

Two options were identified to determine if the generating units equipped with NO_x removal technology could achieve the NO_x allotment thus the BREC system would “take care of itself”. The Wilson Sensitivity Case S1h was established as the worst case scenario as a result of the sensitivity case analyses performed above. This case was became the basis by which the two options would be evaluated. The two options evaluated for the 2007 and 2008 OTAG seasons utilizing actual emission rates are:

- Option 1 – Add SCR systems to Green Units 1 and 2 with assumed NO_x removal efficiencies of 90 percent.
- Option 2 – Add an SCR system to Green Unit 1 with assumed NO_x removal efficiencies of 90 percent.

Additional discussions related to these options including a detail of capital costs, fixed O&M costs and variable O&M costs are presented in Section 6.

In a report entitled “Un-regulated Generation (WKE) Multi-Pollutant Position Report and Proposed Compliance Plan (SO_2, NO_x, Hg)” dated March 27, 2006 by Environmental and Technical Services. WKE identified additional CAIR requirements for NO_x emission limits. Specifically, the report states

> *“Provide additional NO_x control inside the WKE system – Additional NO_x removal will be required to assure the system will be compliant with the CAIR annual NO_x requirements. Option 1 - It appears the installation of an SCR*

> *system on one of the Green units by 2012 would provide a level of reduction sufficient to maintain system compliance through 2018 for a cost of approximately $40,000,000...An evaluation should be made to install a companion SCR on the other Green unit at the same time. This would be the least cost time to do the installation and the value of the sale of allowances significant...."*

Mercury Emissions

The addition of SCR(s) to the Green Unit(s) will result in a co-benefit by reducing mercury emissions. The mercury reduction mechanism is well understood and involves the processes of the new SCR installation and the existing precipitator and FGD systems. Vapor-phase mercury generally exists in two forms in utility flue gas – as elemental mercury and as water soluble, oxidized mercury. Studies document that wet FGD systems effectively remove oxidized mercury from the flue gas streams but remove little elemental mercury. Investigations which studied the effect a SCR catalyst has on flue gas mercury speciation reveal that a change occurs resulting in an increase in the percentage of oxidized mercury as the flue gas moves across the SCR. Since elemental mercury is present in most flue gas streams and may be the predominant form, the installation of the SCR can potentially improve overall mercury emissions reduction.

EPA issued the CAMR on March 15, 2005 to permanently cap mercury emissions and consists of two phases. The Phase I cap commences in 2010. Phase I would be achieved by co-benefit mercury removal as a result of operation of existing air pollution control devices (SCR, precipitators, and FGD). Phase II begins in 2018 and establishes a lower limit of mercury emission. This lower limit will require additional control measures which may include the installation of equipment and systems to control mercury emissions.

Again, reference is made to the report entitled "Un-regulated Generation WKE Multi-Pollutant Position Report and Proposed Compliance Plan (SO_2, NO_x, Hg)" dated March 27, 2006 by Environmental and Technical Services, WKE has studied the co-benefit reduction of mercury emissions. The report identified a plan for the co-benefit mercury emission reduction which included the Green Units. The report noted:

> *"Based upon what is currently known about the CAMR and the anticipated Hg Allowance program. The State of Kentucky is expected to utilize the model rule and the allocated allowances are expected to be sufficient to balance the mercury emissions at least for Phase I. This assumption is based on expected co-benefit mercury removal as a result of operation of existing air pollution control devices (SCR, precipitator, and scrubber). WKE currently has only limited knowledge about its mercury removal capabilities with the existing control equipment. Using data from EPA and EPRI sources, and mercury testing that was done on the Green units as a part of the coal reburn project, assumptions can be made that:*
>
> - *Coleman will achieve 95% removal with the scrubber only.*

- *Station Two achieves 85% reduction with the existing SCR and FGD system (non-oxidized)*
- *Wilson achieves 85% reduction with the existing SCR and FGD system.*
- *Green is achieving 79% reduction with the existing FGD system*
- *Reid is achieving 30% reduction with the existing precipitator.*

However, information from other sources indicates that:

- *Coleman will achieve 25% removal with the scrubber only – 80% is possible with the addition of a duct catalyst.*
- *Station Two achieves 50% reduction with the existing SCR and FGD system – 85% is achievable with the new FGD (oxidized)*
- *Wilson achieves 50% reduction with the existing SCR and FGD system – 85% is achievable with the new FGD (oxidized)*
- *Green is achieving 40% reduction with the existing FGD system*
- *Reid is achieving 10% reduction with the existing precipitator.*

Although there is considerable uncertainty regarding the actual mercury emissions from the WKE units, it appears that the company is in a good position with regard to mercury through Phase I. Further study and testing is required to better determine the impacts of the Phase II requirements. However, any additional control equipment that is installed to provide enhanced removal of SO_2 and NO_x emissions will significantly improve WKE's position on mercury."

Other Unit Causes

Other major causes for forced outages of the BREC system units during the 2004 and 2005 OTAG season include:

- Coleman Unit 1 tripped on June 5, 2004 due to #4 turbine bearing vibration. The source of the problem was not identified.
- Green Unit 1 was shutdown to wash air heaters in June 2004 and June 2005. Green Unit 2 was shutdown to wash air heaters in September 2004. This may be the result of combustion of high percentage blends of petroleum coke.
- A generator field ground occurred in July 2005 on Reid Unit 1.

- HMPL Unit 1 air heater washes forced the unit off-line two times during the 2005 OTAG season. These occurred in May 2005 and July 2005. This may be the direct result of burning high sulfur coal which promotes the formation of ammonium bisulfate.

Conclusions

WKE Plan 8A does not allow for sufficient contingency for operational variances within the BREC system. Therefore, the plan does not allow for the system to "take care of itself." Additional controls will need to be installed on select units within the BREC system to remove additional NO_x emissions to ensure future unit compliance with the current allocation of NO_x allowances.

Improvements to heat rate and any reduction in the forced outages which occur will aid in the overall compliance of the system to meet its intended target performances. Specifically, balancing of the burners and coatings (either weld overlay or other coatings) on the furnace waterwall tubes will aid in the reduction of forced outages due to tube failures. Also, utilizing a coal for fuel which is closer to the design of the steam generator will result in fewer tube failures.

NO_x Compliance Plan - Future Improvements

Introduction

Future NO_x Compliance Plan improvements were identified as a result of Stanley Consultants' evaluation of:

- WKE Plan 8A and WKE Plan 5B performance evaluation for the OTAG seasons of 2004 and 2005. The performance evaluation utilized the 2004 and 2005 performance parameters of capacity and availability factors and heat rate information.
- WKE Plan 8A performance evaluation for the OTAG seasons of 2007 and 2008. The performance evaluation utilized the anticipated capacity and availability factors and heat rate information obtained from the BREC 2007 – 2010 Budget Work Plan.
- Additional sensitivity analyses were performed to determine the impacts of changes in availability and heat rate.

Additional NO_x Removal Equipment

Stanley Consultants determined from the evaluations of the WKE Plans that additional NO_x removal equipment was needed. This determination was based upon:

1. The evaluation performed of the WKE Plan 5B compliance plan performance, which included SCRs on the Green Units 1 and 2. The results of this evaluation determined that WKE Plan 5B would allow for sufficient NO_x removal to accommodate future projected unit capacity and availability factors and heat rate. Any variations caused by NO_x equipment failure events, unit specific forced outage events, and additional system generation requirements could also be accommodated by WKE Plan 5B. Therefore, the installation of SCRs are recommended for the Green Units as originally planned in WKE

Plan 5B. This recommendation is reinforced by the recognition by WKE that additional NO_x allowances will need to be purchased during the Phase I Clean Air Act period. In addition, beginning in Phase II of the Clean Air Act period, any banked allowances will be depleted and WKE will be in a position that will require either the purchase of CAIR Annual NO_x allowances or the implementation of additional controls. The following is an excerpt from the March 27, 2006 Western Kentucky Energy Report titled "Unregulated Generation (WKE) Multi-pollutant Position Report and Proposed Compliance Plan (SO_2, NO_x, Hg)":

> *"WKE has a NO_x SIP Call Ozone Season allowance bank of 815 allowances as of the end of 2005. Of these 14 are associated with the City of Henderson, Station Two. WKE has completed a cost sharing mechanism with the facility owners which provides for splitting these remaining allowances between the parties. This agreement also provides for furnishing allowance to HMPL to offset emissions for the Station One units. NO_x allowances remaining in the bank are expected to rollover into the CAIR Ozone Season Bank. Results from the latest WKE model run indicate that the system will just comply with the CAIR Ozone Season emission requirements through approximately 2018, after which the bank will be depleted and allowances would need to be purchased. Additionally, the CAIR Annual NO_x emission allowance allocations are not expected to be sufficient to offset emissions with the first year of the rule. With consideration of currently forecasted unit utilizations (which are higher than those used in previous reports), for most years of Phase I, a small number of allowances will have to be purchased, with increasing quantities toward the end of this Phase. With the beginning of Phase II WKE will have depleted any banked allowances and be in a position that will require either the purchase of CAIR Annual NO_x allowances or the implementation of additional controls no later than 2015."*

2. An evaluation of WKE Plan 8A for future compliance in the OTAG seasons during the years 2007 and 2008 resulted in a lack of allowances to cover the generation of NO_x emissions for the BREC system to be self sufficient. WKE Plan 8A does not allow for sufficient variations which may result from NO_x equipment failures, unit specific forced outage events and additional system generation requirements. Therefore, in order to provide for the generation needs of the BREC system while complying with the current allotment of NO_x allowances, Stanley Consultants recommends the installation of SCR systems on the Green Units.

Performance Data

Stanley Consultants review of the performance data indicated that if the WKE Plan 5B had been implemented, additional excess NO_x allowances would have resulted during the OTAG seasons of 2004 and 2005. Excess NO_x allowances were banked during the OTAG season of 2004 under the WKE Plan 8A, however, these excess allowances were used in 2005 due to variations caused by NO_x equipment failure events, unit specific forced outage events, and additional system generation requirements.

Stanley Consultants evaluated the WKE Plan 8A to determine if the plan would allow the BREC system to "take care of itself" during the 2007 and 2008 OTAG seasons under a range of operating scenarios. Stanley Consultants analyzed the current system performance and provided a projection based on the current WKE Plan 8A and the BREC 2007 – 2010 Budget Work Plan. Sensitivity analyses were also performed to aid in the identification of future operational exposures. The evaluation revealed that the WKE Plan 8A could not "take care of itself" if any of the units equipped with SCRs, either Wilson or one of the HMPL Units, experienced operational difficulties. These difficulties would result in the respective availability factor being reduced an additional 50 percent of the base case load availability (such an event would be the loss of a major piece of equipment such as a boiler feed pump, forced draft, primary air, or induced draft fans) and if the estimated additional tons of NO_x due to variations caused by NO_x equipment failure events, unit specific forced outage events, and additional system generation requirements were taken into account.

2004 & 2005 Performance

The WKE Plan 8A and WKE Plan 5B Excel spreadsheet models were utilized in determination of the impacts resulting from the operational variations experienced during the OTAG seasons of 2004 and 2005 as compared to the predicted performance resulting from the original plan assumptions. The results of the evaluation of WKE Plan 5B during the OTAG seasons of 2004 and 2005 are provided in Table 6-1 below. In summary, WKE Plan 5B would have results as noted:

- The 2004 OTAG Season performance evaluation resulted in an additional 548.2 NO_x allowances than the WKE Plan 8A.
- The 2005 OTAG Season performance evaluation resulted in an additional 906.6 NO_x allowances than the WKE Plan 8A.

In addition, Table 6-1 documents a comparison of the WKE Plan 5B modeled NO_x controlled tons versus the WKE Plan 8A modeled NO_x controlled tons, the WKE reported tons, and the additional tons caused by NO_x equipment failure events, unit specific forced outage events, and additional system generation requirements.

Table 6-1 Comparison of 2004 & 2005 OTAG Season Plan 5B & Plan 8A Controlled NO_x Tons

Unit	2004						2005					
	Plan 5B NO_x Tons[1]	Plan 8A NO_x Tons[2]	WKE Additional NO_x Events Tons[3]	Total Plan 5B NO_x Tons[4]	Total Plan 8A NO_x Tons[5]	WKE Reported NO_x Tons[6]	Plan 5B NO_x Tons[7]	Plan 8A NO_x Tons[8]	WKE Additional NO_x Events Tons[3]	Total Plan 5B NO_x Tons[9]	Total Plan 8A NO_x Tons[10]	WKE Reported NO_x Tons[11]
Coleman Unit 1	611.9	474.3	30.0	641.9	504.3	515	812.3	658.5	38.8	851.1	697.3	737
Coleman Unit 2	699.1	514.9	30.4	729.5	545.3	544	793.0	609.8	5.5	798.5	615.3	636
Coleman Unit 3	655.5	505.2	0.7	656.2	505.9	539	810.2	646.4	83.8	894.0	730.2	757
HMPL Unit 1	84.4	84.2	80.6	165.0	164.8	199	149.7	148.9	53.2	202.9	202.1	213
HMPL Unit 2	80.2	79.4	386.7	466.9	466.1	214	142.8	143.6	65.9	208.7	209.5	204
Green Unit 1	129.9	638.5	12.4	142.3	650.9	649	181.7	904.7	(1.5)	180.2	903.2	888
Green Unit 2	139.9	654.6	45.8	185.7	700.4	683	173.6	859.1	37.5	211.1	896.6	882
Wilson Unit	259.0	257.0	263.5	522.5	520.5	421	288.1	287.1	130.3	418.4	417.4	424
Reid Unit 1	24.2	24.2	0.4	24.6	24.6	45	298.0	298.0	57.4	355.4	355.4	433
Reid CT	2.9	2.9	---	2.9	2.9	47	1.5	1.5	---	1.5	1.5	23
TOTAL	2,687.0	3,235.2	850.5	3,537.5	4,085.7	3,856	3,650.9	4,557.6	470.9	4,121.8	5,028.5	5,197
Excess NO_x Allowances (Tons)	1,813.0	1,264.8	---	962.5	414.3	644	849.1	---	---	378.2	---	---
Additional NO_x Allowances Needed (Tons)	---	---	---	---	---	---	---	57.6	---	---	528.5	697
Allocated NO_x Allowances	4,500	4,500	---	4,500	4,500	4,500	4,500	4,500	---	4,500	4,500	4,500

Notes:

(1) Values were calculated in the Plan 5B 2004 OTAG Season Evaluation. Refer to Section 4.

(2) Values were calculated in the Plan 8A 2004 OTAG Season Evaluation. Refer to Section 3.

(3) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were determined from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls."

(4) This is a calculated value from the sum of "2004 Plan 5B NO_x Tons" column and "2004 WKE Additional NO_x Events Tons" column.

(5) This is a calculated value from the sum of "2004 Plan 8A NO_x Tons" column and "2004 WKE Additional NO_x Events Tons" column.

(6) Values were provided in the WKE spreadsheet entitled "2004 NO_x Actuals Compared to Budget" Refer to Appendix G.

(7) Values were calculated in the Plan 5B 2005 OTAG Season Evaluation. Refer to Section 4.

(8) Values were calculated in the Plan 8A 2005 OTAG Season Evaluation. Refer to Section 3.

(9) This is a calculated value from the sum of "2005 Plan 5B NO_x Tons" column and "2005 WKE Additional NO_x Events Tons" column.

(10) This column is a calculated value from the sum of "2005 Plan 8A NO_x Tons" column and "2005 WKE Additional NO_x Events Tons" column.

(11) Values were provided in the WKE spreadsheet entitled "2005 NO_x Actuals Compared to Budget" Refer to Appendix G.

2007 & 2008 Performance

Stanley Consultants evaluated the WKE Plan 8A for the 2007 and 2008 OTAG seasons under a range of operating scenarios. The WKE Plan 8A Excel spreadsheet model was utilized in determining variations from the original plan assumptions in the evaluation of the approaching 2007 and 2008 OTAG seasons projected performance. Stanley Consultants analyzed the current system performance and provided a projection based on the current WKE Plan 8A. A base case was developed for the 2007 and 2008 OTAG seasons. A discussion of the parameters used in the 2007 and 2008 base cases is located in Section 5. Table 6-2 documents the results of the projected 2007 and 2008 OTAG season performance using actual emission rates and the additional projected amount of tons of NO_x due to forced outage events, SCR warm up events, and other generation events.

- The 2007 OTAG season modeled NO_x tons indicates an excess of 240.7 tons of NO_x allowances would be available, however, when the 2007 additional NO_x events are added to the WKE Plan 8A total NO_x tons, the results indicate that 365.0 NO_x allowances are needed.

- The 2008 OTAG season modeled NO_x tons indicates an excess of 263.4 tons of NO_x allowances would be available; however, when the 2008 additional NO_x events are added to the WKE Plan 8A total NO_x tons, the results indicate that 342.3 NO_x allowances are needed.

Table 6-2 Base Case 2007 & 2008 OTAG Season Evaluation

Unit	2007 OTAG Season Evaluation			2008 OTAG Season Evaluation		
	Base Case Plan 8A NO_x Tons(1)	2007 Additional NO_x Events Tons(2)	Base Case Plan 8A 2007 Total NO_x Tons(3)	Base Case Plan 8A NO_x Tons(4)	2008 Additional NO_x Events Tons(2)	Base Case Plan 8A 2008 Total NO_x Tons(5)
Coleman Unit 1	766.1	34.4	800.5	763.8	34.4	798.2
Coleman Unit 2	727.8	17.9	745.7	712.3	17.9	730.2
Coleman Unit 3	757.6	42.3	799.9	758.1	42.3	800.4
HMPL Unit 1	129.2	86.8	216.0	129.4	86.8	216.2
HMPL Unit 2	123.7	128.6	252.3	123.3	128.6	251.9
Green Unit 1	786.5	5.5	792.0	789.5	5.5	795.0
Green Unit 2	783.3	41.6	824.9	780.9	41.6	822.5
Wilson Unit	266.6	216.7	483.3	260.9	216.7	477.6
Reid Unit 1	217.5	31.9	249.4	217.4	31.9	249.3
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0
Total	4,558.3	605.7	5,164.0	4,535.6	605.7	5,141.3
Excess NO_x Allowances (Tons)	240.7	---	---	263.4	---	---
Additional NO_x Allowances Needed (Tons)	---	---	365.0	---	---	342.3
Allocated NO_x Allowances	4,799	---	4,799	4,799	---	4,799

Notes:

(1) Values were calculated in the 2007 OTAG Season Evaluation. Refer to Section 5.

(2) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events tons were projected for 2007 and 2008 based on information from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls" The projections are presented in Section 5.

(3) This is a calculated value from the sum of "2007 Base Case Plan 8A NO_x Tons" column and "2007 Additional NO_x Events Tons" column.

(4) Values were calculated in the 2008 OTAG Season Evaluation. Refer to Section 5.

(5) This is a calculated value from the sum of "2008 Base Case Plan 8A NO_x Tons" column and "2008 Additional NO_x Events Tons" column.

Options

Three options were identified to determine the best plan to meet future NO_x compliance. These options are presented below in order of least risk to maximum exposure. These options were identified to determine if the generating units equipped with NO_x removal technology could achieve the NO_x allotment thus the BREC system would "take care of itself". The Wilson Sensitivity Case S1h was established as the worst case scenario as a result of the sensitivity case analyses performed above. This case became the basis by which the three options would be evaluated.

Option 1

Option 1 includes the installation of SCR systems with a NO_x removal efficiency of 90 percent on Green Units 1 and 2, including ammonia unloading and storage, economizer modifications, Induced Draft fan modifications, and air heater enameled basket modifications. Option 1 was evaluated for the 2007 and 2008 OTAG seasons utilizing actual emission rates.

Option 1 2007 Results

- The 2007 Base Case Plan 8A indicates an additional 365.0 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 1 Base Case Plan 8A which generated an excess of 715.0 tons of NO_x allowances (includes 168.2 tons of additional NO_x emissions for the SCR systems added to Green Units 1 and 2).

- The 2007 Wilson Sensitivity Case S1h evaluation indicates an additional 713.9 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 1 Sensitivity Case S1h which generated an excess of 504.7 tons of NO_x allowances (includes 168.2 tons of additional NO_x emissions for the SCR systems added to Green Units 1 and 2).

Option 1 2008 Results

- The 2008 Base Case Plan 8A indicates an additional 342.3 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 1 Base Case Plan 8A which generated an excess of 738.1 tons of NO_x allowances (includes 168.2 tons of additional NO_x emissions for the SCR systems added to Green Units 1 and 2).

- The 2008 Wilson Sensitivity Case S1h evaluation indicates an additional 705.6 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 1 Sensitivity Case S1h which generated an excess of 513.6 tons of NO_x allowances (includes 168.2 tons of additional NO_x emissions for the SCR systems added to Green Units 1 and 2).

Option 2

Option 2 includes installation of a SCR system with a 90 percent removal efficiency on Green Unit 1, including ammonia unloading and storage, economizer modifications, induced draft fan modifications, and air heater enameled basket modifications.

Option 2 2007 Results

- The 2007 Base Case Plan 8A indicates an additional 365.0 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 2 Base Case Plan 8A which generated an excess of 177.7 tons of NO_x allowances (includes 85 tons of additional NO_x emissions for the Green Unit 1 SCR).

- The 2007 Wilson Sensitivity Case S1h evaluation indicates an additional 713.9 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 2 Sensitivity Case S1h with an additional 101.5 tons of NO_x allowances needed (includes 85 tons of additional NO_x emissions for the Green Unit 1 SCR).

Option 2 2008 Results

- The 2008 Base Case Plan 8A indicates an additional 342.3 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 2 Base Case Plan 8A which generated an excess of 202.7 tons of NO_x allowances (includes 85 tons of additional NO_x emissions for the Green Unit 1 SCR).
- The 2008 Wilson Sensitivity Case S1h evaluation indicates an additional 705.6 tons of NO_x allowances (includes additional NO_x emissions due to other operational events) are needed compared to the Option 2 Sensitivity Case S1h with an additional 90.5 tons of NO_x allowances needed (includes 85 tons of additional NO_x emissions for the Green Unit 1 SCR).

Table 6-3 documents the comparison of the 2007 Base Case Plan 8A to the Base Case Plan 8A with Options 1 and 2, and the Wilson Sensitivity Case S1h to the Sensitivity Case S1h with Options 1 and 2. Table 6-4 documents the comparison of the 2008 Base Case Plan 8A to the Base Case Plan 8A with Options 1 and 2, and the Wilson Sensitivity Case S1h to the Sensitivity Case S1h with Options 1 and 2.

Option 3

Option 3 assumes the continuation of the current WKE Plan 8A and presents the maximum exposure due to operational events. Option 3 requires the purchase of additional NO_x allowances. BREC provided a NO_x allowance price forecast which was derived from a spreadsheet entitled "GII Allowance Forecasts 02-24-06.xls."

1. Based on the 2007 analysis the additional NO_x allowance tons needed, ranged from 365 tons in the Base Case to 713.94 tons for the Wilson Sensitivity Case S1h. The 2007 emission allowance price ($/ton) is $2,459. The cost of purchasing the required NO_x allowances would range from $897,535 to $1,755,726 per year.

2. Based on the 2008 analysis the additional NO_x allowance tons needed, ranged from 342 tons in the Base Case to 706 tons for the Wilson Sensitivity Case S1h. The 2008 emission allowance price ($/ton) is $2,262. The cost of purchasing the required NO_x allowances would range from $773,604 to $1,596,972 per year.

Table 6-3 2007 Base Case Versus Worst Case Sensitivity Case S1h

Unit	Additional NO_x Events Tons(1)	2007 Base Case Plan 8A						2007 Plan 8A Sensitivity Case S1h					
		Base Case NO_x Tons(2)	Base Case Total NO_x Tons(3)	Option 1 Base Case NO_x Tons(4)	Option 1 Base Case Total NO_x Tons(5)	Option 2 Base Case NO_x Tons(6)	Option 2 Base Case Total NO_x Tons(7)	Wilson Unit Sensitivity Case S1h NO_x Tons(8)	Wilson Unit Sensitivity Case S1h Total NO_x Tons(9)	Option 1 Sensitivity Case S1h NO_x Tons(10)	Option 1 Sensitivity Case S1h Total NO_x Tons(11)	Option 2 Sensitivity Case S1h NO_x Tons (12)	Option 2 Sensitivity Case S1h Total NO_x Tons(13)
Coleman Unit 1	34.4	766.1	800.5	766.1	800.5	766.1	800.5	851.2	885.6	851.2	885.6	851.2	885.6
Coleman Unit 2	17.9	727.8	745.7	727.8	745.7	727.8	745.7	808.6	826.5	808.6	826.5	808.6	826.5
Coleman Unit 3	42.3	757.6	799.9	757.6	799.9	757.6	799.9	841.8	884.1	841.8	884.1	841.8	884.1
HMPL Unit 1	86.8	129.2	216.0	129.2	216.0	129.2	216.0	143.6	230.4	143.6	230.4	143.6	230.4
HMPL Unit 2	128.6	123.7	252.3	123.7	252.3	123.7	252.3	137.5	266.1	137.5	266.1	137.5	266.1
Green Unit 1	5.5	786.5	792.0	158.8	249.3(14)	158.8	249.3(14)	873.9	879.4	176.5	267.0(14)	176.5	267.0(14)
Green Unit 2	41.6	783.3	824.9	162.8	287.6(15)	783.3	824.9	870.3	911.9	180.9	305.7(15)	870.3	911.9
Wilson Unit	216.7	266.6	483.3	266.6	483.3	266.6	483.3	148.1	148.1(16)	148.1	148.1(16)	148.1	148.1(16)
Reid Unit 1	31.9	217.5	249.4	217.5	249.4	217.5	249.4	443.8	475.7	443.8	475.7	443.8	475.7
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.1	5.1	5.1	5.1	5.1	5.1
Total	605.7	4,558.3	5,164.0	3,310.1	4,084.0	3,930.6	4,621.3	5,123.9	5,512.9	3,737.1	4,294.3	4,426.5	4,900.5
Excess NO_x Allowances (Tons)	---	240.7	---	1,488.9	715.0	868.4	177.7	---	---	1,061.9	504.7	372.5	---
NO_x Allowances Needed (Tons)	---	---	365.0	---	---	---	---	324.9	713.9	---	---	---	101.5
Allocated NO_x Allowances	---	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799

Notes:

(1) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events were projected for 2007 and 2008 based on information from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls." The projections are presented in Section 5.

(2) Values were calculated in the Base Case OTAG Season Evaluation. Refer to Section 5.

(3) This is a calculated value from the sum of "Base Case NO_x Tons" column and "Additional NO_x Events Tons" column.

(4) Values were calculated in the Option 1 Base Case Evaluation. Variations to the Base Case evaluation were to add SCR systems with 90 percent removal efficiencies to Green Units 1 and 2.

(5) This is a calculated value from the sum of "Option 1 Base Case NO_x Tons" column and "Additional NO_x Events Tons" column.

(6) Values were calculated in the Option 2 Base Case Evaluation. Variations to the Base Case evaluation were to add an SCR system to Green Unit 1 with a 90 percent removal efficiency.

(7) This is a calculated value from the sum of "Option 2 Base Case Total NO_x Tons" column and "Additional NO_x Events Tons."

(8) Values were calculated in the Sensitivity Case evaluation. Refer to Section 5.

(9) This is a calculated value from the sum of "Wilson Unit Sensitivity Case S1h NO_x Tons" column and "Additional NO_x Events Tons" column.

(10) Values were calculated in the Option 1 Sensitivity Case S1h Evaluation. Variations to the Wilson Unit Sensitivity Case S1h were to add SCR systems to the Green Units 1 and 2 with a 90 percent removal efficiency.

(11) This is a calculated value from the sum of "Option 1 Sensitivity Case S1h NO_x Tons" column and "Additional NO_x Events Tons" column.

(12) Values were calculated in the Option 2 Sensitivity Case S1h Evaluation. Variations to the Wilson Unit Sensitivity Case S1h were to add an SCR system to Green Unit 1 with a 90 percent removal efficiency.

(13) This is a calculated value from the sum of "Option 2 Sensitivity Case Sh1 NO_x Tons" column and "Additional NO_x Events Tons" column.

(14) In addition to "Additional NO_x Events Tons" noted in Column 1, an estimate of 85 tons for SCR warm-up events and SCR load reduction/low temperature events was added.

(15) In addition to "Additional NO_x Events Tons" noted in Column 1, an estimate of 83.2 tons for SCR warm-up events and SCR load reduction/low temperature events was added.

(16) Additional NO_x events not accounted for.

Table 6-4 2008 Base Case Versus Worst Case Sensitivity Case S1h

Unit	Additional NO_x Events Tons(1)	2008 Base Case Plan 8A						2008 Plan 8A Sensitivity Case S1h					
		Base Case NO_x Tons(2)	Base Case Total NO_x Tons(3)	Option 1 Base Case NO_x Tons(4)	Option 1 Base Case Total NO_x Tons(5)	Option 2 Base Case NO_x Tons(6)	Option 2 Base Case Total NO_x Tons(7)	Wilson Unit Sensitivity Case S1h NO_x Tons(8)	Wilson Unit Sensitivity Case S1h Total NO_x Tons(9)	Option 1 Sensitivity Case S1h NO_x Tons(10)	Option 1 Sensitivity Case S1h Total NO_x Tons(11)	Option 2 Sensitivity Case S1h NO_x Tons(12)	Option 2 Sensitivity Case S1h Total NO_x Tons(13)
Coleman Unit 1	34.4	763.8	798.2	763.8	798.2	763.8	798.2	848.7	883.1	848.7	883.1	848.7	883.1
Coleman Unit 2	17.9	712.3	730.2	712.3	730.2	712.3	730.2	791.4	809.3	791.4	809.3	791.4	809.3
Coleman Unit 3	42.3	758.1	800.4	758.1	800.4	758.1	800.4	842.3	884.6	842.3	884.6	842.3	884.6
HMPL Unit 1	86.8	129.4	216.2	129.4	216.2	129.4	216.2	143.7	230.5	143.7	230.5	143.7	230.5
HMPL Unit 2	128.6	123.3	251.9	123.4	252.0	123.4	252.0	137.1	265.7	137.0	265.6	137.0	265.6
Green Unit 1	5.5	789.5	795.0	159.4	249.9(14)	159.4	249.9(14)	877.2	882.7	177.2	267.7(14)	177.2	267.7(14)
Green Unit 2	41.6	780.9	822.5	162.3	287.1(15)	780.9	822.5	867.7	909.3	180.4	305.2(15)	867.7	909.3
Wilson Unit	216.7	260.9	477.6	260.9	477.6	260.9	477.6	144.9	144.9(16)	144.9	144.9(16)	144.9	144.9(16)
Reid Unit 1	31.9	217.4	249.3	217.4	249.3	217.4	249.3	447.7	479.6	447.7	479.6	447.7	479.6
Reid CT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14.9	14.9	14.9	14.9	14.9	14.9
Total	605.7	4,535.6	5,141.3	3,287.0	4,060.9	3,905.6	4,596.3	5,115.6	5,504.6	3,728.2	4,285.4	4,415.5	4,889.5
Excess NO_x Allowances (Tons)	---	263.4	---	1,512.0	738.1	893.4	202.7	---	---	1,070.8	513.6	383.5	---
NO_x Allowances Needed (Tons)	---	---	342.3	---	---	---	---	316.6	705.6	---	---	---	90.5
Allocated NO_x Allowances	---	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799	4,799

Notes:

(1) Refer to Appendix D for a description of the events that resulted in additional tons of NO_x. WKE additional NO_x events were projected for 2007 and 2008 based on information from the WKE spreadsheet entitled "04 and 05 Organized Data from WKE NO_x Models.xls." The projections are presented in Section 5.
(2) Values were calculated in the Base Case OTAG Season Evaluation. Refer to Section 5.
(3) This is a calculated value from the sum of "Base Case NO_x Tons" column and "Additional NO_x Events Tons" column.
(4) Values were calculated in the Option 1 Base Case Evaluation. Variations to the Base Case evaluation were to add SCR systems with 90 percent removal efficiencies to Green Units 1 and 2.
(5) This is a calculated value from the sum of "Option 1 Base Case NO_x Tons" column and "Additional NO_x Events Tons" column.
(6) Values were calculated in the Option 2 Base Case Evaluation. Variations to the Base Case evaluation were to add an SCR system to Green Unit 1 with a 90 percent removal efficiency.
(7) This is a calculated value from the sum of "Option 2 Base Case Total NO_x Tons" column and "Additional NO_x Events Tons."
(8) Values were calculated in the Sensitivity Case evaluation. Refer to Section 5.
(9) This is a calculated value from the sum of "Wilson Unit Sensitivity Case S1h NO_x Tons" column and "Additional NO_x Events Tons" column.
(10) Values were calculated in the Option 1 Sensitivity Case S1h Evaluation. Variations to the Wilson Unit Sensitivity Case S1h were to add SCR systems to the Green Units 1 and 2 with a 90 percent removal efficiency.
(11) This is a calculated value from the sum of "Option 1 Sensitivity Case S1h NO_x Tons" column and "Additional NO_x Events Tons" column.
(12) Values were calculated in the Option 2 Sensitivity Case S1h Evaluation. Variations to the Wilson Unit Sensitivity Case S1h were to add an SCR system to Green Unit 1 with a 90 percent removal efficiency.
(13) This is a calculated value from the sum of "Option 2 Sensitivity Case Sh1 NO_x Tons" column and "Additional NO_x Events Tons" column.
(14) In addition to "Additional NO_x Events Tons" noted in Column 1, an estimate of 85 tons for SCR warm-up events and SCR load reduction/low temperature events was added.
(15) In addition to "Additional NO_x Events Tons" noted in Column 1, an estimate of 83.2 tons for SCR warm-up events and SCR load reduction/low temperature events was added.
(16) Additional NO_x events not accounted for.

Cost

Capital and O&M costs were developed for Options 1 and 2 which include the addition of SCR NO_x control technology on Green Units 1 and 2. Capital costs were also identified for the installation of the remaining neural network systems that were not installed but were identified and are a portion of WKE Plan 8A. The capital costs for the neural network systems were included in the present value analysis for Option 2. The capital costs in this report are appropriate for budgetary purposes.

Capital

The capital costs for Options 1 and 2 are documented in the detailed conceptual cost estimate in Table 6-5. The conceptual capital cost estimate includes:

- Material and equipment
- Initial catalyst
- Labor
- Permitting
- Flow modeling
- Start-up, testing and reagent costs
- Engineering, construction, administration, and contingency

Costs are not included for items such as financing fees, insurance, spare parts, operator training or commissioning time and expense.

Budgetary proposals were solicited from vendors for the SCR systems, catalyst, and ammonia storage and associated equipment and are noted in Appendix I.

Table 6-5 SCR Conceptual Cost Estimate

Item Description	Labor & Material	
	Option 1 Total	Option 2 Total
Demolition of Ductwork and Steel	$570,000	$300,000
Economizer Modifications	$3,542,000	$1,864,000
Ductwork and Support Structures(1)	$23,408,000	$12,320,000
SCR Reactor	$3,146,000	$1,656,000
Foundations(2)	$2,134,000	$1,123,000
Catalyst	$12,550,000	$6,605,000
Sootblowers, Piping, and Controls	$3,354,000	$1,765,000
Flow Model Study	$295,000	$155,000
Ammonia System(3)	$10,682,000	$5,622,000
Air Heater Enameled Basket Modifications & Ash Handling Extension Components Only	$8,210,000	$4,321,000
Induced Draft Fan Modifications	$6,441,000	$3,390,000
Electrical and Instrumentation	$5,996,000	$3,156,000
Relocation of Existing Equipment and Utilities	$498,000	$262,000
Mobilization/Demobilization	$2,058,000	$1,083,000
Equipment Rental	$4,117,000	$2,167,000
Subtotal	$86,999,000	$45,789,000
Probable Construction Cost	$86,999,000	$45,789,000
Engineering/Construction Coordination (7%)	$6,090,000	$3,205,000
Contingency (10%)	$8,700,000	$4,579,000
Permitting, Modeling, etc.	$125,000	$125,000
Start-Up, Testing and Reagent	$150,000	$150,000
Project Cost Total	$102,064,000	$53,848,000
Probable Project Cost (Owner's Cost)	$102,064,000	$53,848,000

Notes:

(1) Includes gas ductwork from economizer outlet to SCR, between SCR and air heater and SCR bypass ductwork, existing duct modifications, and support structures. Also includes insulation and lagging, expansion joints, and dampers.

(2) Includes excavation and backfill.

(3) Includes ammonia unloading and storage, ammonia vaporization, and injection and associated piping.

Capital costs developed for the missing neural network systems are presented in Table 6-6.

Table 6-6 NN Systems Conceptual Cost Estimate

Item Description	Total
Coleman Unit 1 NN	$380,000
Coleman Unit 3 NN	$380,000
HMPL Unit 1 NN	$380,000
HMPL Unit 2 NN	$380,000
Wilson Unit NN	$380,000
Subtotal	$1,900,000
Probable Construction Cost	$1,900,000
Engineering/Construction Coordination (7%)	$133,000
Contingency (10%)	$190,000
Project Cost Total	$2,223,000
Probable Project Cost (Owner's Cost)	$2,223,000

Incremental Fixed O&M

Incremental Fixed O&M costs include:

- Labor O&M
- Non-Labor O&M
    - Maintenance material includes the costs for any spare parts and the associated labor cost for installation. The costs include periodic replacement of items such as ammonia nozzles, the injection system, and maintenance material for various SCR subsystems.

This study assumes no additional operating or maintenance personnel would be required for the addition of the SCR NO_x control technology on the Green Unit(s). It is assumed that the current staff is trained in the operation and maintenance of SCR(s) and their associated subsystems and has sufficient knowledge and training to handle the ammonia-related safety systems. This assumption was made based on the fact that the HMPL Units have SCR systems and cross training between the operation and maintenance staffs of the HMPL and Green units is or would occur. Therefore, no additional training costs are included. An allocation of labor costs for the operation and maintenance of the SCR systems was determined from information provided by BREC which is noted in the 2006 BREC Annual Budget.xls spreadsheet. These costs were adjusted for the additional generation capacity difference in the HMPL and Green Units and were appropriately escalated to achieve the total costs noted below. Table 6-7 documents the Fixed O&M costs.

Table 6-7 Estimated 2009 Fixed O&M Costs

Description	Green Unit 1 Costs	Green Unit 2 Costs
Labor O&M (\$/yr) ⁽¹⁾	\$210,000	\$206,000
Non-Labor O&M (\$/yr) ⁽¹⁾	\$324,000	\$317,000
Administrative and Support Labor	\$0	\$0
Total Fixed O&M Costs	\$534,000	\$523,000

Notes:
(1) Cost information was obtained from the spreadsheet entitled "2006 BREC Annual Budget.xls" for the HMPL units SCR Labor and Non-Labor O&M budget items. These costs were adjusted for the additional Green Unit generation capacity (MW). The resulting values were escalated at 3 percent per year.

Incremental Variable O&M

The installation of SCR equipment on the Green Unit 1 and 2 will result in incremental variable O&M costs which include the cost of catalyst replacement, ammonia consumption, and auxiliary power.

1. Stanley Consultants assumes anhydrous ammonia will be used as anhydrous ammonia storage exists on the site for the HMPL Unit SCRs. The cost for ammonia delivered to the site was obtained from the BREC 2007-2010 Work Plan for the HMPL Station. The ammonia consumption is based on 0.0008 tons/MWh which was included in the BREC 2007-2010 Work Plan.

2. The auxiliary power includes the additional power requirements for the induced draft fans; the power consumption of the ammonia vaporizers, the ammonia dilution air blowers and heaters, the ammonia pumps, the damper seal air fans; and various electrical and control users. The induced draft fan power includes the power requirement to overcome the increased system pressure drop. The power consumption is presented in Table 6-8.

Table 6-8 Estimated SCR Power Consumption

Description	Green Unit 1 (kW)(1)	Green Unit 2 (kW)(1)
ID Fans Increase in Motor Power Consumption	1,121.0	1,084.0
Ammonia Vaporizers Power Consumption	26.0	24.0
Dilution Air Blower Power Consumption	35.1	32.1
Air Heaters Power Consumption	94.0	87.0
Ammonia Pump Power Consumption	0.4	0.4
Damper Seal Air Fans Power Consumption	45.0	43.0
Electrical and Control Power Consumption	66.0	64.0
Total Power kW Consumption Estimated	1,388.0	1,334.0

Notes:
(1) Values derived from the S&L 1999 Study Appendix D.

The total variable operating costs are documented in Table 6-9. These costs which were included in the analysis were determined to occur in 2009 and reflect the cost in 2009 current dollars.

Table 6-9 Estimated 2009 SCR Variable O&M Costs

Description	Green Unit 1	Green Unit 2
Ammonia Cost ($/yr)(1)	$654,000	$650,000
Emulsified Sulfur Cost ($/yr)(2)	$47,000	$47,000
Power Cost ($/yr)(3)	$256,000	$246,000
Heat Rate Penalty ($/yr)(4)	$136,000	$175,000
Total Annual Costs - Estimated	$1,093,000	$1,118,000

Notes:
(1) Cost information was obtained from the spreadsheet entitled "BREC 2007-2010 Work Plan Variable O&M.xls" and "BREC Production Cost Model 1-11-06.xls".
(2) Cost information was obtained from the spreadsheet entitled "2006 BREC Annual Budget.xls" These costs were adjusted for the additional Green Unit generation capacity (MW).
(3) The cost is based on the Total kW power consumption documented in Table 6-7 multiplied by 8760 hours multiplied by 90 percent (the assumed capacity factor) multiplied by $23.43/MWh (which is the cost for generation in 2009 obtained from the BREC 2007-2010 Work Plan included in the Green Exec Summary Table.xls spreadsheet).
(4) The heat rate penalty value, Btu/kWh, utilized the information found in the 1999 S&L Study. The penalty identified was used in a calculation to determine the costs associated with the increase in heat rate.

Present Value Analysis

The objective of the present value analysis is to project the annualized costs associated with the installation of the SCR(s) and associated subsystems on the Green Unit(s). The analysis assumed the installation of the SCR(s) would be complete and startup of the new SCR(s) would occur in the calendar year of 2009. The analysis also assumed there would be no interest during construction (IDC) in the total capital costs. The purchase of additional NO_x allowances needed to cover any deficit in 2007 and 2008 prior to the installation of the SCR(s) was determined and the costs of these purchases were included. These purchases would only occur during the OTAG seasons. The purchase or sale of any additional NO_x allowances which may occur during the period of 2009 through 2023 as identified in each of the options were also included. The revenue from the sale of NO_x allowances was considered as a credit when determining the net operating costs. The operation of the SCR will occur during the entire year beginning in 2009 and will continue to operate when the respective unit(s) operates throughout the balance of the evaluation period. Thus the model will approximate the operation of the unit(s) during the period identified in the Clean Air Interstate Rule. Annual costs were projected for the period covering the calendar years of 2007 through 2023. The total annual costs are presented in costs which would occur in January 1, 2007. The total projected costs include the following items:

- Debt Service – The debt service costs assume the total project is financed (there is no payment from general funds) and includes an interest rate of 5.75% for a 34 year finance period.
- Fixed O&M (as noted in Table 6-7)
- Variable O&M (as noted in Table 6-9)
- The purchase of additional NO_x allowances or the sale of excess NO_x allowances

The present value analysis compared four options which are described below:

<u>Option 1</u>: Installation of SCRs and subsystems on both of the Green Units. The Total Probable Project Capital Cost (Owner's Cost) is $102,064,000 (Refer to Table 6-5). This option includes the purchase of allowances during the calendar years 2007 and 2008 and the sale of excess NO_x allowances annually during the period of 2009 through 2023.

Option 2A: The installation of a single SCR and subsystems on Green Unit 1. The Total Probable Project Capital Cost (Owner's Cost) of the SCR is $53,848,000 (Refer to Table 6-5). This option also includes the addition of NN systems on the Coleman Units 1 and 3, HMPL Units 1 and 2, and the Wilson Unit. The neural network systems have a probable cost of $2,223,000 (Refer to Table 6-6). The installation of the neural network systems are assumed to occur in 2007 and 2008 and the costs are equally divided accordingly. The total Project Capital Cost (Owner's Cost) is $56,071,000. This option includes the purchase of allowances during the calendar years 2007 and 2008 and the sale of excess NO_x allowances annually during the period of 2009 through 2023.

Option 2B: This option is a risk sensitivity run of the previous Option 2A. This option assumes the Wilson unit will operate only 50 percent of the time during the summer months of May through September. Thus, implementation of this option will require the purchase of additional allowances in lieu of selling excess NO_x allowances. *This option results in the purchase of NO_x allowances annually from* 2007 through 2023.

In the Options 1, 2A, and 2B, the catalyst was assumed to be sized for each application and is based on an estimated life of 16,000 hours. After 16,000 hours, the empty layer of catalyst bed will be filled with a full layer. Thus, a new catalyst layer would be installed after 3 years and every 2 years thereafter. The replacement cost for the catalyst is assumed linear (but is escalated) over the period of 27 years after the installation of initial catalyst resulting in a life cycle of 30 years.

Option 3A: This option assumes the continued operation of WKE Plan 8A. This option results in the purchase of NO_x allowances annually from 2007 through 2023 at an annual average rate similar to the rate of purchase during the calendar years 2004 and 2005.

Option 3B: This option is a risk sensitivity run of the previous Option 3A. This option assumes the Wilson unit will operate only 50 percent of the time during the summer months of May through September. This option results in the purchase of NO_x allowances annually from 2007 through 2023.

The detailed present value analysis for the three options and the two risk sensitivity runs are documented in Table J-1 of Appendix J. A summary of the present value analysis is noted in Table J-2 of Appendix J.

Financial Parameters

The financial parameters were identified and discussed with BREC are as follows:

- The capital required to purchase the SCR(s) and neural network systems identified in each of the options would be obtained from the Rural Development (formerly Rural Utility Services) department of the US Department of Agriculture. The systems and equipment would be project financed (100 percent) over a term period of 34 years at an interest rate of 5.75 percent.
- There is no allowance for IDC.
- The discount rate was assumed to be eight percent.
- The escalation rate was assumed to be three percent.
- The probable project costs for the SCR(s) and related subsystems are presented in Table 6-5.
- The neural network systems probable project costs are presented in Table 6-6.

Operating Costs

The estimated fixed O&M costs are presented in Table 6-7.

The estimated SCR power consumption are presented in Table 6-8.

The estimated SCR variable O&M costs are shown in Table 6-9.

Purchase/Sale of NO_x Allowances

The Options assume the SCRs would not be available for operation prior to the calendar year 2009, and a conservative number of additional NO_x allowances will be needed during the calendar years 2007 (714 tons) and 2008 (706 tons). Refer to Table 6-3 and 6-4 under the column entitled "Wilson Unit Sensitivity Case S1h Total NO_x Tons."

Beginning in the calendar year 2009, each option utilized the average of the 2007 and 2008 modeled tons for the annual purchase or sale of NO_x allowances. This annual average of NO_x allowances was increased by multiplying by 2.4 (or 12 months divided by 5 months) to account for the year round OTAG season as follows:

- Option 1 included the sale of 1,222 NO_x allowances. This value was averaged based on the modeled tons of excess NO_x allowances for the Option 1 Sensitivity Case S1h. Refer to Table 6-3 and 6-4 under the column entitled "Option 1 Sensitivity Case S1h Total NO_x Tons."
- Option 2A included the sale of 457 NO_x allowances. This value was averaged based on the modeled tons of excess NO_x allowances for the Option 1 Base Case. Refer to Table 6-3 and 6-4 under the column entitled "Option 2 Base Case Total NO_x Tons."

- Option 2B included the purchase of 230 NO_x allowances. This value was averaged based on the modeled tons of excess NO_x allowances for the Option 2 Sensitivity Case S1h. Refer to Table 6-3 and 6-4 under the column entitled "Option 2 Sensitivity Case S1h Total NO_x Tons."

- Option 3A included the purchase of 849 NO_x allowances. This value was averaged based on the modeled tons of excess NO_x allowances for the Base Case. Refer to Table 6-3 and 6-4 under the column entitled "Base Case Total NO_x Tons."

- Option 3B included the purchase of 1,703 NO_x allowances. This value was averaged based on the modeled tons of excess NO_x allowances for the Wilson Unit Sensitivity Case S1h. Refer to Table 6-3 and 6-4 under the column entitled "Wilson Unit Sensitivity Case S1h Total NO_x Tons."

Results

Results of the present value analysis are documented in Table 6-10 below:

Table 6-10 Present Value Analysis Results

Item	Total 2007 through 2023 Operating Costs				
	Option 1	**Option 2A**	**Option 2B**	**Option 3A**	**Option 3B**
Debt Service	$103,496,770	$57,083,543	$57,083,543	$0	$0
Fixed O&M	$19,652,859	$9,938,209	$9,938,209	$0	$0
Variable O&M:					
Ammonia	$24,374,531	$12,400,906	$12,400,906	$0	$0
Emulsified Sulfur	$1,747,824	$873,912	$873,912	$0	$0
Catalyst	$43,926,101	$22,196,789	$22,196,789	$0	$0
Auxiliary Power	$9,365,391	$4,775,592	$4,775,592	$0	$0
Heat Rate Penalty	$5,627,565	$2,500,245	$2,500,245	$0	$0
Sale of Excess NO_x Allowances	($28,539,810)	($10,673,235)	$0	$0	$0
Purchase of Additional NO_x Allowances Needed	$3,352,698	$3,352,698	$8,724,348	$23,181,093	$43,126,263
Net Costs	$183,003,929	$102,448,659	$118,493,544	$23,181,093	$43,126,263
Present Value of Net Costs	$85,822,592	$49,176,373	$57,793,767	$13,644,261	$24,356,422

Option 3A results in the least cost option; however, there are associated risks with this option. The availability of NO_x allowances for purchase and the price for these allowances will place BREC at the discretion of market forces.

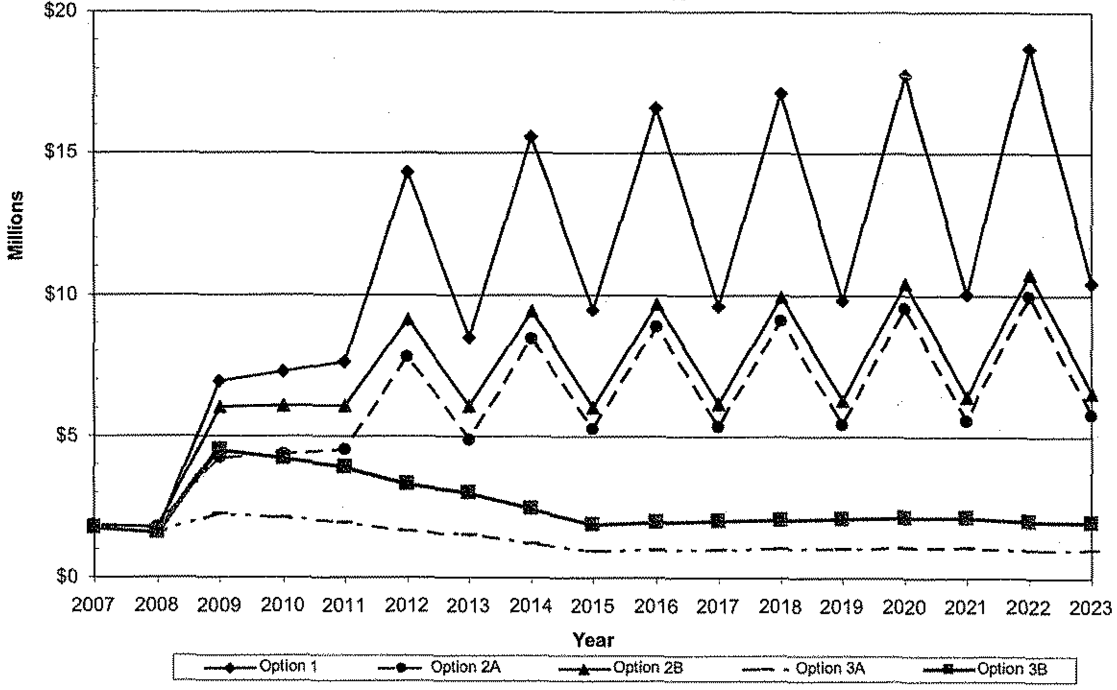
The installation of one SCR and subsystems on Green Unit 1 (Option 2) may reduce the risk of variable market availability of and pricing for allowances, provide for the co-benefit reduction of mercury emissions and the associated market forces on mercury emission credits and the partial assurance of system compliance with CAIR annual NO_x requirements. As noted above, under certain operating scenarios, additional allowances would be needed. Thus BREC will incur additional risks due to market forces.

The installation of two SCRs and related subsystems on the Green units (Option 1) will reduce the risk of variable market availability of and pricing for allowances, provide for the co-benefit reduction of mercury emissions and the associated market forces on mercury emission credits and the assurance of system compliance with CAIR Annual NO_x requirements.

The total annual net costs for each option for the period 2007-2023 are depicted graphically in Figure 6-1.

Figure 6-1

Total Annual Net Costs



Option 1 - Install 2 SCR Systems **Option 2** - Install 1 SCR System

Option 3 - Purchase NO_x Allowances

Section 7

Conclusions and Recommendations

Conclusions

The following summary of conclusions is the direct result of this study:

1. WKE Plan 8A includes the use of innovative technologies (NN, AOFA, and coal re-burn system) to achieve NO_x reductions. The uses of coal re-burn and AOFA systems affect the combustion within the boiler. Low NO_x operation as a result of the implementation of the coal re-burn and AOFA system in an existing boiler in combination with a coal supply containing a higher sulfur content will result in increases in LOI, waterwall tube wastage, and an increase in CO emissions and opacity. These conditions may also lead to a reduction in unit availability.

2. WKE chose to proceed with WKE Plan 8A. In a letter dated February 19, 2002 WKE agreed to hold BREC harmless for any additional capital or O&M costs that it would be liable for with the installation of the technologies and scope of work as identified in WKE Plan 5B if it had been used to comply with the Kentucky SIP regulation. The limits identified in WKE Plan 5B were budget costs, but as stated in the February 19, 2002 letter, the limit protections were extended to WKE to include actual costs.

3. The upgrade of plant control systems to distributed controls systems and neural network systems will result in additional NO_x control and other advantages will result. However, the control system, analyzers and instruments must be maintained and periodically calibrated. If not, the advantages of the sophisticated digital control and neural network systems will be lost. Upon review of the WKE reported NO_x emissions rates, the systems may not be optimally tuned.

4. Contingency cost estimates were eliminated from WKE's compliance plan cost projections. Stanley Consultants typically adds ten percent of a project capital cost for contingencies.

5. The impact of unit starts on NO_x allowance consumption was not included in the Power Technology review, S&L Report nor considered by WKE.

6. All units are assumed to be 100 percent available during the OTAG season. This availability was an incorrect assumption, as evidenced by forced outage causes and planned outage events and the additional NO_x emissions which are a result of these events.

7. The HMPL units would utilize SCR/DCS/NN/BOP to achieve 90 percent NO_x reduction in the WKE Plan 8A and 5B. This information was obtained from the WKE NO_x Compliance Plan Meeting Big Rivers and the City of Henderson Power Point Presentation dated April 18, 2001. The WKE Plan 8A and 5B spreadsheets note the HMPL Units 1 and 2 would utilize SCR systems to achieve 90 percent NO_x reduction. The noted differences could result in a flaw in the WKE Plan 8A or 5B.

8. The S&L report documents the following:

   Use of high sulfur coal with SCR also creates concern over ABS (ammonium bisulfate) deposition but goes further in that it can create corrosion problems, "blue plume" opacity problems, and can potentially lead to accelerated deactivation of the SCR catalyst.

   This issue would also result in the lack of availability of the units which were retrofitted with SCR units, due to the corrosion in the air heaters and associated ductwork or due to air heaters plugging from sulfuric acid and calcium sulfate attack. As a result, overall unit availability will be impacted negatively and will have an effect on the NO_x compliance.

9. Upon review of the WKE NBV and CWIP report, Stanley Consultants concludes that not all of the neural network systems have been installed. Refer to Table 2-5.

10. WKE Plan 8A failed to perform as predicted based on several observations. Refer to Table 3-9 and 3-10. The observed and documented deficiencies result from the following:

    a. Differences in specific unit heat rates. WKE Plan 8A is sensitive to heat rate impacts with higher heat rates resulting in higher NO_x emissions. The heat rates utilized to develop the plan were higher than the actual heat rates for all the units except Reid Unit 1 and the 2005 Green Unit 1. These actual heat rate values would result in a lower NO_x emission for the OTAG season.

    b. Differences in specific unit emission rates. WKE Plan 8A is sensitive to emission rate with higher emission rates resulting in higher NO_x emissions. The emission rates utilized to develop the plan were lower than the actual emission rates for Coleman Units 1, 2, and 3, HMPL Unit 1, and Reid Unit 1 in both 2004 and 2005. The HMPL Unit 2 actual emission rate in 2005 was also higher than the WKE Plan 8A emission rate. These actual emission rate values would result in a higher NO_x emission for the OTAG season. The Coleman Units did not achieve the NO_x reduction efficiencies and this issue was noted in the settlement agreement between WKE and Mobotec. An alternate SNCR control strategy was offered by Mobotec to WKE for implementation on the Coleman Unit(s) in recognition of the need to further reduce NO_x emissions.

c. Additional NO_x emissions due to other events. WKE Plan 8A did not include additional NO_x emissions due to such events as SCR warm up periods and operation of the Wilson Unit Pulverizer No. 3. These actual emissions would result in a higher NO_x emission than planned for the OTAG season.

d. Planned and forced outages. The WKE Plan 8A did not include additional NO_x emissions due to the loss of specific units equipped with SCRs or higher efficiency NO_x removal equipment. The results are more NO_x emissions being generated than planned.

11. WKE Plan 5B would provide for compliance during the 2004 and 2005 OTAG seasons as additional NO_x emissions would be removed due to the installation of SCRs on the Green Units. Refer to Table 4-4 and 4-5. The difference in additional NO_x emissions removed would compensate for any increases observed in the 2004 and 2005 OTAG seasons resulting from differences in specific unit heat rates, differences in specific unit emission rates, additional NO_x emissions due to other events, and planned and forced outages.

12. Additional NO_x control technologies will need to be installed on the Green Units to remove additional NO_x emissions to ensure future system compliance with the current allocation of NO_x allowances. Refer to Table 6-3 and 6-4.

13. Green Units 1 and 2 SCR system construction costs in 2006 dollars are estimated as follows:

a.	Green Unit 1 - 231 Megawatt (MW) unit	$53,848,000
b.	Green Unit 2 - 223 MW unit	$48,216,000

(1) 2009 O&M costs for the SCR systems are as follows:

(a) Annual Fixed O&M – $534,000 for Green Unit 1 and $523,000 for Green Unit 2.

(b) Annual Variable O&M – $1,093,000 for Green Unit 1 and $1,118,000 for Green Unit 2

Recommendations

The following recommendations are made as a result of this study:

1. BREC should consider several options to determine the best plan to meet future NO_x compliance. These options are presented below in order of least risk to maximum exposure.

    a. Option 1 presents the least risk exposure which may result from operational events and results in excess allowances which can be banked or sold even in the worst case scenario. Option 1 includes the installation of SCRs and subsystems on both Green Units. The system costs include ammonia unloading and storage, economizer modifications, induced draft fan modifications, and air heater enameled basket modifications. The estimated capital cost for this option is $102,064,000. The present value annual cost associated with this option is $85,822,592. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

        (1) The addition of SCR(s) and subsystems to the Green Unit(s) will result in a co-benefit reduction of mercury emissions. The EPA issued the Clean Air Mercury Rule (CAMR) on March 15, 2005 to permanently cap mercury emissions and consists of two phases. The Phase I cap commences in 2010. The intent of the Phase I cap is to achieve mercury emissions reductions through the operation of existing air pollution control devices (SCR, precipitators, and FGD). The co-benefit reduction of mercury emissions could generate a revenue stream from mercury credits which would be sold on the open market during Phase I. The analysis of this revenue stream is outside the scope of this report and would require sensitivity studies of both price and mercury emissions removal efficiencies by the various technologies. Phase II begins in 2018 and establishes a lower limit of mercury emission. This lower limit may require additional control measures which may include the installation of equipment and systems to control mercury emissions.

        (2) The addition of SCRs and subsystems on the Green Units would assure system compliance with CAIR Annual NO_x requirements and allow for a revenue stream if excess allowances are sold.

        (3) The installation of SCRs and subsystems on both Green Units reduces the risk to BREC in the event of a failure at either of the HMPL Units or the Wilson Unit.

    b. Option 2 represents the next least risk exposure. Option 2 will generally cover the NO_x allowances needed in the sensitivity analysis, a small purchase of allowances may be necessary in the worst case scenario. Option 2 includes installation of a SCR and related subsystems on Green Unit 1. The capital costs include ammonia unloading and storage, economizer modifications, induced draft fan modifications, and air heater enameled basket modifications. The estimated capital cost for the SCR portion of this option is $53,848,000. Also included in the Option 2 capital costs are the installation of additional neural network systems at an estimated capital cost of $2,223,000. These control systems were added to aid in the support of NO_x removal. These systems were not included in the Option 1 as Option 1 would produce less tons of emissions than the allowance tons under all operating scenarios. This same condition is not true under Option 2. Under certain operating scenarios, more emissions were generated than the allowances available. Therefore, to reduce the additional risk associated with allowance purchases, the control systems were installed. The total capital cost for this option is $56,071,000. The present value analysis Option 2A includes the sale of allowances generated after the installation of the SCR and subsystems. This analysis does not account for a major event occurrence, for example, the Wilson Unit were available only 50 percent of the OTAG season. Option 2A present value annual costs are $49,176,373. Present value analysis Option 2B evaluates the purchase of allowances if a major event (such as the Wilson Unit were available only 50 percent of the OTAG season) were to occur. Option 2B present value annual costs are $57,793,767. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

(1) Co-benefit mercury removal would be realized with the installation of an SCR and subsystems on Green Unit 1 which would enhance BREC's position relative to mercury emissions reduction but to a lesser degree as provided by Option 1.

(2) The installation of a SCR and associated subsystems on Green Unit 1 reduces the risk for but will not assure under all operational conditions studied, system compliance with CAIR Annual NO_x requirements. In the event of a failure of either of the HMPL Units or the Wilson Unit SCRs, it is possible that NO_x allowances would need to be purchased to satisfy annual NO_x requirements. This will place BREC under the market forces of pricing and availability for NO_x allowances which may have similar variability as experienced with trading of SO_2 allowances.

c. Option 3 represents the maximum exposure caused by any operational event. Option 3 relies completely on the purchase of additional NO_x allowances and assumes the continuation of the current WKE Plan 8A. For the period of 2009-2023, the estimated cost of the purchase of approximately 849 to 1,703 tons of NO_x allowances ranges from $951,729 to $4,499,326 annually. The present value analysis Option 3A includes the purchase of additional NO_x allowances. This analysis does not account for a major event occurrence, for example, the

Wilson Unit were available only 50 percent of the OTAG season. Option 3A present value costs are $13,644,261. Present value analysis Option 3B evaluates the purchase of allowances and accounts for a major event occurrence. Option 3B present value costs are $24,356,422. Appendix J documents the results, assumptions, and costs used in the determination of the present value analysis. In addition to the annual costs, other issues of risk exposure which need to be considered are:

(1) Option 3 represents the maximum exposure to the risks of variable market availability and pricing of NO_x allowances, similar to the variability experienced with trading of SO_2 allowances.

(2) In addition, Option 3 does not allow for any co-benefit reduction of mercury emissions.

2. The NO_x removal equipment on Coleman Units 1, 2 and 3, Green Units 1 and 2, HMPL Units 1 and 2, Wilson, and Reid Unit 1 need to be tuned to achieve their optimal removal efficiencies.

3. A CEMS NO_x analyzer is needed in the HMPL bypass ductwork or stack.

4. Install a neural network system on Coleman Units 1 and 3, HMPL Units 1 and 2, and Wilson unit.

5. Improve the specific unit's heat rate.

6. Reduce the unit's forced outages.

7. Utilize a coal which more closely resembles the design fuel for the various steam generators.

Appendix A

NO_x Compliance Plan Evaluation Third-Party Report List

Plant	Document Title	Document Date	Prepared By
Coleman	A Comparative Study of System ROFA Applied to Coleman Unit #2 (200112WKE001)	6/29/2001	MOBOTEC
Coleman	Overfire Air System P&ID Drawing (Sheet 1) (DWG G-3837-003)	12/20/2001	GE Energy Services
Coleman	Overfire Air System GA Drawings (Sheets 1-6) (DWG G3837D-001)	12/21/2001	GE Energy Services
Coleman	Coal Reburn System P&ID Drawing (Sheet 1) (DWG G3837-002)	12/27/2001	GE Energy Services
Coleman	Coleman 2 Overfire Air System Process Design EER Report No. 3866	8/1/2003	GE Energy Services
Coleman	C3 NO_x Removal System	12/15/2003	Foster Wheeler
Coleman	C3 Overfire Air Modifications	1/15/2004	Foster Wheeler
Coleman	Comprehensive Combustion Improvement Program	7/13/2000	Innovative Combustion Technologies
Green	Baseline Boiler Performance Test Report Unit 1 DBR Contract 100118	5/19/2000	Babcock Borsig Power
Green	Baseline Boiler Performance Test Report Unit 2 Contract 100117	4/3/2000	Babcock Borsig Power
Green	Tail End Selective Catalytic Reduction Study Tow reactor Option	8/18/2000	Babcock Borsig Power

Plant	Document Title	Document Date	Prepared By
Green	Boiler Testing to Identify Opportunities for Improvement in Boiler Performance Units 1 and 2	8/20/2000	Innovative Combustion Technologies, Inc.
HMPL	Flow Modeling of the City of Henderson Precipitators Job No. DX22 G859	2002	Powergen
HMPL	Fan Evaluation for SCR Project	2002	Burns & McDonnell
HMPL	SCR Project – Fuel Analysis	2002	Burns & McDonnell
HMPL	Baseline Boiler Performance Report for HMPL Units 1 and 2	3/21/2002	Clean Air Engineering
HMPL	Boiler Testing to Identify Opportunities for Improvement in Boiler Performance and NO_x Emissions Units 1 and 2	8/20/2000	Innovative Combustion Technologies
Wilson	I.D. Fans Upgrade Estimate	2002	Babcock Borsig Power & Babcock – Hitachi
Wilson	Low NO_x Optimization Testing Results	8/20/1999	Foster Wheeler
Wilson	Baseline Boiler Performance Test Report	10/16/2000	Babcock Borsig Power
Wilson	SCR Evaluation Study	10/31/2000	Babcock Borsig Power
Wilson	Evaluation of Alternative SCR Systems – Plant Improvement Alternatives	11/8/2000	Riley Power, Inc.
Wilson	Addendum to Baseline Boiler Performance Test Report	1/26/2001	Babcock Borsig Power
Wilson	Wilson Station Preliminary SCR Drawings	2/5/2001	Babcock Borsig Power
Wilson	Selective Catalyst Reduction Design Spreadsheet	4/9/2001	Babcock Borsig Power & Babcock – Hitachi
Wilson	Conformed Contract Document for Air Preheater	6/20/2002	Babcock Borsig Power & Babcock – Hitachi
Wilson	Fan Performance Requirement Comparison	6/24/2002	Babcock Borsig Power
Wilson	Air Heater Performance Evaluation Report	1/28/2003	Babcock Borsig Power
Wilson	After Perforated Plant Install Air Heater Performance Evaluation Report	3/3/2003	Babcock Borsig Power
Wilson	SCR Acceptance Tests	10/18/2003	E-On Engineering

Appendix B

Net Book Value Report Summary
NO$_x$ Control Emission Equipment

Unit	Plan 8A Method of Reduction	Project Number	NBV Report Acquisition Value	Acquired on Date	NBV or CWIP
Coleman 1	ROFA System	WKE00111/S	$4,319,545.62	07/01/04	NBV
	Boiler Control System	WK8050000	$257,872.38	03/01/00	NBV
	Windows DCS Boiler Control System – Combustion Controls	WKE00079	$268,063.75	09/01/00	NBV
	Windows DCS Boiler Control System	WK00C111B	$310,049.38	05/01/01	NBV
	Yokogawa CEM Recorder	WK00C186U	$3,244.15	01/01/01	NBV
	NO$_x$ Analyzer	WK04C047U	$15,033.10	09/01/05	NBV
Coleman 2	OFA System	WKE00111/S	$1,808,258.70	02/01/04	NBV
	Neural Network	WKE00111/S	$346,926.00	02/01/04	NBV
	Yokogawa CEM Recorder	WK00C186U	$3,244.14	01/01/01	NBV
	NO$_x$ Analyzer	WK04C047U	$15,033.10	09/01/05	NBV
Coleman 3	AOFA System	WKE00111/S	$1,782,989.00	12/01/04	NBV
	Yokogawa CEM Recorder	WK00C186U	$3,244.14	01/01/01	NBV
	NO$_x$ Analyzer	WK04C047U	$15,033.09	09/01/05	NBV
Coleman Common	Yokogawa CEM Recorder	WK00C186U	$3,599.67	01/01/01	NBV

Unit	Plan 8A Method of Reduction	Project Number	NBV Report Acquisition Value	Acquired on Date	NBV or CWIP
Green 1	OFA/Coal Re-burn System	WKE00111/S	$5,341,124.66	11/01/04	NBV
	DCS Hardware	WKE00111/S	$301,246.95	11/01/04	NBV
	Neural Network	WKE00111/S	$319,700.00	11/01/04	NBV
	DCS Boiler Controls Auxiliary Monitors	WK03G026B	$2,566.70	08/01/03	NBV
Green 2	OFA/Coal Re-burn System	WKE00111/S	$5,704,558.39	01/01/03	NBV
	Neural Network	WKE00111/S	$345,979.00	01/01/03	NBV
	DCS Hardware	WKE00111/S	$333,146.27	01/01/03	NBV
	DCS Boiler Controls Auxiliary Monitors	WK03G026B	$2,566.69	08/01/03	NBV
HMPL 1 & 2	SCR	WKE00111	31,041,551.71	thru 12/31/05	CWIP
HMPL Common	Digital Controls – Stack Emissions	WK02S068U	$50,626.27	03/01/03	NBV
Reid 1	Gas Burners	WKE00111/S	$2,529,509.16	05/01/04	NBV
Reid CT	CEMS Computer	WK02S074U	$18,577.01	09/01/03	NBV
	Dual Fire Burners	WKE00111/S	$816,466.27	05/01/04	NBV
Reid/HMPL Common	Recorder, Data Networks, w/Wiring, Connectors, and Server	WK04S068U	$14,212.64	07/01/05	NBV
Wilson	Ammonia System	WKE00111/S	$2,999,930.30	12/01/03	NBV
	Data Acquisition System & HMI – Client Server Software, monitors, servers, and PI archiving historian	WKE00111/S		12/1/03	NBV
	Burner Management System	WKE00111/S		12/1/03	NBV
	SCR System	WKE00111/S	$31,177,088.19	12/01/03	NBV
	NO$_x$ Analyzer TLI Building	WKE00111/S	$360,147.78	12/01/03	NBV
	AC Motor in Ammonia Feed Pump System	WK01W022U	$57,066.45	02/01/02	NBV

Unit	Plan 8A Method of Reduction	Project Number	NBV Report Acquisition Value	Acquired on Date	NBV or CWIP
Wilson (continued)	ID Fan	WKE00111/S	$4,988,804	12/01/03	NBV
	Rake Sootblowers	WKE00111/S	$1,407,218	12/01/03	NBV
	Dilution/Seal Air System	WKE00111/S	$2,175,649	12/01/03	NBV
	Additional Charges on Ammonia Feed Pump System AC Drives/AC Motor	WK01W022U	$5,326.56	06/01/02	NBV

Appendix C

Forced Outage Causes and Planned Outage Events

General

Below are outages that resulted in more than anticipated NO_x emissions during the 2004 and 2005 OTAG seasons.

Unit Outage Report Summary May 1 through September 2004[(1)]

Start Date	Class[(2)(3)]	Description	Duration Hours	Duration Minutes
Coleman Unit 1:				
4/29/04	UO2	Tube leak in the reheat section of the boiler. Total outage was 48 hours 44 minutes	5	19
5/10/04	UO4	Unit offline to repair wet bottom gas leaks	11	55
5/25/04	PO, XPO	Planned maintenance outage - 241.8 hours, extended planned outage - 14.1 hours, extended planned hours due to tube leaks after chemical clean	255	55
6/5/04	UO1	Unit tripped due to #4 turbine bearing vibration	20	22
7/4/04	UO4	Unit off line to balance B ROFA Fan	37	13
8/13/04	UO1	Unit tripped on low air flow, instrument technicians were blowing back air flow taps	6	36
9/13/04	UO4	Unit off line to deslag boiler and wash air heaters	87	7

Unit Outage Report Summary May 1 through September 2004(1) (Continued)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
Coleman Unit 2:				
5/1/04	UO4	Unit offline to set mechanical overspeed	9	1
5/1/04	UO1	Incorrectly packed C row sootblowers stuffing boxes	8	33
5/4/04	UO1	Unit tripped on low air flow	1	19
7/16/04	UO4	One tube leak in superheat section at 8L sootblower	28	43
8/10/04	UO4	Unit off line to repair B precipitator inlet	26	28
8/13/04	UO1	Unit tripped on low drum level. Cleaned suction strainers on boiler feed pumps	34	38
9/28/04	UO4	Unit off to repair tube leak in the HRA section west side of boiler. Total outage was 57 hours 11 minutes.	48	28
Coleman Unit 3:				
5/1/04	PO	Planned maintenance outage	418	0
6/20/04	UO1	Unit removed from service due to two tube leaks in economizer section of the boiler	43	26
6/22/04	UO1	Unit tripped on high turbine exhaust hood temperature	1	36
6/26/04	UO4	Unit off line to repair B air heater sootblower	22	32
7/23/04	UO1	Unit tripped on high drum level	3	0
8/13/04	UO1	Unit tripped on low turbine oil pressure	12	19
Green Unit 1:				
5/23/04	UO1	Unit tripped offline when the turbine valves went shut.	1	48
5/31/04	UO2	Steak leak on #1 reheat stop valve flange on the underside of the turbine.	10	52
6/4/04	UO4	Wash air heaters due to pluggage. Waterwall tube leak repaired.	41	5
6/13/04	UO2	Repair tube leak in reheat outlet section of boiler.	41	16
7/9/04	UO1	Power pack failure which resulted in the UPS system upset.	7	49
8/2/04	UO1	Waterwall tube leak	50	4
9/16/04	UOI	Waterwall tube leak	34	23
9/30/04	UO3	Reheater tube leak. Total outage was 41 hours 2 minutes.	11	46

Unit Outage Report Summary May 1 through September 2004(1) (Continued)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
Green Unit 2:				
5/19/04	BPO	Planned maintenance outage.	131	42
6/25/04	UO1	Unit tripped offline to loss of UPS system.	6	18
9/18/04	UO4	Wash air heaters.	42	32
9/26/04	UO1	Unit tripped offline. Cause unknown.	1	22
9/30/04	UO1	Unit tripped offline. Cause unknown. Total outage was 1 hour 28 minutes.	0	6
HMPL Unit 1:				
6/8/04	UO1	Unit tripped due to loss of 'A' seal air fan.	8	30
7/5/04	UO1	Waterwall tube leak.	72	59
8/21/04	UO1	Waterwall tube leak.	58	58
8/23/04	UO2	Waterwall tube leak.	515	17
HMPL Unit 2:				
5/2/04	UO1	Tripped while running normal turbine valve test. Orifices plugged and cracked line in lube oil system.	73	17
5/14/04	UO4	Inspect/repair precipitators.	33	29
5/17/04	UO2	Reheater tube leaks.	64	7
5/20/04	UO1	Unit tripped on reverse current.	3	20
8/30/04	UO1	Instrument air problems.	29	9
Reid Unit 1:				
5/11/04	UO3	Unit removed from service under a controlled shutdown.	15	4
5/16/04	UO1	Unit tripped offline due to loss of flames/flame scanner	3	36
5/29/04	BPO XPO	Planned maintenance outage. Turbine controls work.	672 59	0 6
6/28/04	EPO	Unit tripped offline due to problems/testing of new turbine controls.	3	49
6/29/04	EPO	Run prescheduled electrical and mechanical turbine overspeed tests.	1	8
6/30/04	EPO	Unit tripped while undergoing new turbine controls tuning/testing	5	12
6/30/04	EPO	Unit tripped while unit undergoing new turbine controls tuning/testing.	4	15
7/1/04	RS	Reserve standby.	123	59
7/8/04	UO1	'B' scanner cooling fan tripped. 'A' fan failed to autostart resulting in the unit tripping.	1	35

Unit Outage Report Summary May 1 through September 2004(1) (Continued)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
7/8/04	UOI	Unit tripped while start-up was in progress from BMS upset outage.	1	54
7/10/04	RS	Reserve standby.	18	15
7/16/04	RS	Reserve standby.	64	54
7/22/04	RS	Reserve standby.	264	39
8/4/04	RS	Reserve standby. Total outage was 1904 hours 51 minutes.	1394	30
Wilson:				
5/27/04	UO1	Break in KU line insulator in switchyard.	34	27
6/2/04	UO1	Tube leak on economizer inlet header tube.	42	0
6/4/04	UO1	Unit tripped due to fire in the wet bottom.	8	45
6/15/04	UO1	Tube failure approx. 3 ft below IR-21.	61	7
7/19/04	UO4	Repair #5 heater.	32	7
8/25/04	UO1	Tube leak approx. 4 ft below IR-21.	57	50
9/27/04	UO1	Tube leaks on west wall and in knees.	58	7

Notes:

(1) OTAG Season.

(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), PMO (planned maintenance outage), XPO/EPO (extended planned outage), UO4 (deferred), and RS (reserve shutdowns).

(3) Forced Outages (UO = Unplanned) include items colded as UO1 (immediate), UO2 (delayed), UO3 (postponed) and SF (start-up failure).

Unit Outage Report Summary May 1 through September 30, 2005(1)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
Coleman Unit 1:				
5/18/05	UO1	Unit trip tube leak in wet bottom area	49	23
6/15/05	UO1	Unit tripped falsely for low vacuum	3	17
7/9/05	UO2	Tube leak in wet bottom area of boiler	38	41
7/13/05	UO1	Tube leak in wet bottom area of boiler	89	38
Coleman Unit 2:				
6/8/05	UO1	Unit trip ground faults on 2B Boiler Feed Pump and 2A Primary Air Fan	36	47
7/13/05	UO1	Unit trip low vacuum (lost start-up power)	83	32
9/25/05	UO4	Unit offline to repair wet bottom tube leak	32	3
9/29/05	UO2	Tube leak in convection superheater adjacent to 6R sootblower	32	31
Coleman Unit 3:				
5/21/05	UO1	Unit trip due to drum high level	1	31
7/3/05	UO1	Unit trip loss of flame	1	29
7/29/05	UO4	Unit off to repair oil leak on switchyard metering PT	77	37
9/4/05	UO4	Unit offline to repair leak in east side economizer drain line	23	38
Green Unit 1:				
5/16/05	UO1	Unit manually tripped due to boiler master fuel trip indication	6	24
6/10/05	UO4	Wash air heaters.	50	19
9/7/05	UO2	Unit removed from service due to scrubber bleed pump suction line blowing apart.	8	54
9/29/05	UO1	Unit tripped due to loss of fires in the boiler	1	34
9/29/05	PO	Planned outage. Total outage was 54 hours 30 minutes.	26	0
Green Unit 2:				
5/8/05	UO1	Unit tripped while testing turbine valves.	2	41
5/25/05	UO2	Waterwall tube leak. Tube split open along overlay weld seam.	21	10
6/18/05	UO1	Unit tripped due to low drum level.	1	1
8/30/05	UO1	Unit tripped due to loss of fires.	5	25
9/23/05	BPO	Planned maintenance outage	120	40
9/29/05	UO2	Unit removed from service under a controlled shutdown due to 'A' BFP packing leak.	11	24
9/29/05	UO1	Unit tripped due to high drum level.	3	21

Unit Outage Report Summary May 1 through September 30, 2005(1) (Continued)

Start Date	Class(2)(3)	Description	Duration Hours	Duration Minutes
HMPL Unit 1:				
5/28/05	UO4	Wash air heaters due to pluggage.	50	46
7/1/05	UO4	Wash air heaters due to pluggage.	45	29
8/10/05	UO1	Unit tripped due to a water wall tube leak.	44	12
8/26/05	UO1	Unit tripped due to a water wall tube leak.	45	51
HMPL Unit 2:				
5/20/05	BPO	Modifications to SCR dampers.	181	29
9/16/05	UO4	Unit was removed from service to wash air heaters.	53	27
Reid Unit 1:				
4/30/05	RS	Reserve Shutdown due to OTAG season. Total outage was 795 hours 43 minutes.	794	53
6/17/05	UO1	Unit tripped offline due to the loss of flame scanners on both 'A' and 'B' mills. Apparent cause was a power interruption to the burner management system.	1	36
6/17/05	OU1	Unit tripped offline due to a low drum level.	0	59
7/1/05	UO2	Waterwall tube leak above wet bottom, two economizer leaks and one in the wet bottom.	65	00
7/19/05	UO4	Generator field ground.	91	30
8/4/05	UO4	Unit removed from service to install taps/valves on the generator for the new hydrogen dryer.	25	37
8/23/05	UO1	Unit tripped on low vacuum. Problems with the steam jet air ejector.	8	22
9/9/05	UO4	Unit removed from service to inspect/repair generator field ground connection	172	27
9/17/05	UO1	Unit tripped while attempting to transfer from start-up to auxiliary power.	7	0
Wilson:				
5/10/05	UO1	Experienced problems with cooling fan to the Main Step-up Transformer. Unit tripped when the deluge on the transformer went off.	7	10
5/14/05	UO1	Lightening strike to start-up transformer lines.	14	1
6/3/05	UO4	Repair condensate line on #6 heater.	40	34
7/8/05	UO1	Unit tripped on low drum level during test of #2 BFPT LP stop valve.	3	22
8/2/05	UO1	Unit trip due to boiler tube leak.	36	18
8/9/05	UO1	Unit trip due to boiler tube leak.	30	22
8/10/05	UO1	Unit trip due to boiler tube leak.	66	37

Unit Outage Report Summary May 1 through September 30, 2005[1] (Continued)

Start Date	Class[2][3]	Description	Duration Hours	Duration Minutes
8/24/05	UO1	Unit trip due to boiler tube leak.	45	29
9/21/05	UO4	Unit taken offline to make repairs to weld on #5 heater	6	55

Notes:

(1) OTAG Season.

(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), PMO (planned maintenance outage), XPO/EPO (extended planned outage), UO4 (deferred), and RS (reserve shutdowns).

(3) Forced Outages (UO = Unplanned) include items colded as UO1 (immediate), UO2 (delayed), UO3 (postponed) and SF (start-up failure).

Appendix D

Additional NO_x Emissions Information

General

Below is the WKE evaluation of impacts of forced outage causes and planned outage events (Appendix C).

Additional 2004 NO_x Emissions Information

Unit	Description	Tons of NO_x	Comments
Wilson	SCR warm up after outages - Total 85 hours warm up combustion without NH_3	61.57	1 planned (DA leak repair) 4 forced (tube leaks)
Wilson	Additional emissions due to #3 Mill operation	153.74	Average lbs/MMBtu not using #3 mill is 0.05. Average lbs/MMBtu using #3 mill is 0.078
Wilson	Additional emissions due to CEM heat input delta	41.86	--
Wilson	Additional emissions due to difference in actual heat rate versus plan heat rate	6.35	--
Wilson Total		**263.52**	

Additional 2004 NO_x Emissions Information (Continued)

Unit	Description	Tons of NO_x	Comments
HMPL Unit 1	SCR off due to application of coal drying agent	33.78	Total hours with drying agent and SCR bypass 113
HMPL Unit 1	SCR warm up events from forced outages. Total 51 hours warm up combustion without NH_3	10.77	3 forced outages (1 seal air flow, 2 tube leaks)
HMPL Unit 1	SCR load reduction/low temp events. Total 17 hours low temp combustion without NH_3.	4.33	3 total – 2 maintain compliance 1 for wet coal
HMPL Unit 1	Due to Bypass Max Potential Emissions (5)	17.62	Total FGD bypass hours 32
HMPL Unit 1	Additional emissions due to CEM heat input delta	19.24	--
HMPL Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	(5.15)	--
HMPL Unit 1 Total		**80.59**	
HMPL Unit 2	SCR off due to application of coal drying agent	43.69	Total hours with drying agent and SCR bypass 138
HMPL Unit 2	SCR warm up events from forced outages. Total 35 hours warm up combustion without NH_3	6.15	3 forced outages (2 booster fan trips, 1 unit trip)
HMPL Unit 2	SCR load reduction/low temp events. Total 28 hours low temp combustion without NH_3	8.17	3 total – 2 maintain compliance 1 for wet coal
HMPL Unit 2	Due to By-pass Max Potential Emissions (10)	18.98	Total FGD bypass hours 33
HMPL Unit 2	Due to incorrect linearity event	257.62	This = MPE -0.48 during over-lap with wet coal to take out wet coal effects.
HMPL Unit 2	Due to Cal failure event (1)	10.41	Total 25 hours with MPE due to event
HMPL Unit 2	Additional emissions due to CEM heat input delta	44.40	--

Additional 2004 NO_x Emissions Information (Continued)

Unit	Description	Tons of NO_x	Comments
HMPL Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	(2.73)	--
HMPL Unit 2 Total		**386.69**	
Coleman Unit 1	Additional emissions due to CEM heat input delta	23.00	--
Coleman Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	7.04	--
Coleman Unit 1 Total		**30.04**	
Coleman Unit 2	Additional emissions due to CEM heat input delta	25.86	--
Coleman Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	4.49	--
Coleman Unit 2 Total		**30.35**	
Coleman Unit 3	Additional emissions due to CEM heat input delta	20.14	
Coleman Unit 3	Additional emissions due to difference in actual heat rate versus plan heat rate	(19.42)	
Coleman Unit 3 Total		**0.72**	
Green Unit 1	Additional emissions due to CEM heat input delta	0.84	
Green Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	11.55	
Green Unit 1 Total		**12.39**	

Additional 2004 NO_x Emissions Information (Continued)

Unit	Description	Tons of NO_x	Comments
Green Unit 2	Additional emissions due to CEM heat input delta	26.49	
Green Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	19.34	
Green Unit 2 Total		**45.83**	
Reid Unit 1	Additional emissions due to CEM heat input delta	0.39	
Reid Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	0	
Reid Unit 1 Total		**0.39**	

Additional 2005 NO_x Emissions Information

Unit	Description	Tons of NO_x	Comments
Wilson	SCR warm up after outages - Total 113 hours warm up combustion without NH_3	82.14	WKE estimated 9 unplanned outage events
Wilson	Additional emissions due to #3 Mill operation	30.51	Average lbs/MMBtu not using #3 mill is 0.05. Average lbs/MMBtu using #3 mill is 0.078.
Wilson	Additional emissions due to CEM heat input delta	16.37	--
Wilson	Additional emissions due to difference in actual heat rate versus plan heat rate	1.31	--
Wilson Total		**130.33**	
HMPL Unit 1	SCR warm up events from forced outages. Total 86 hours warm up combustion without NH_3	37.11	Number of events – 8
HMPL Unit 1	SCR load reduction/low temp events. (Wet coal or Mill Problems) Total 57 hours low temp combustion without NH_3	6.24	Number of events – 3
HMPL Unit 1	Booster Fan Trips (FGD Bypass Max Potential Emissions (3)	3.69	Total FGD bypass hours 6
HMPL Unit 1	Additional Emissions due to monitor problem	9.89	Number of events – 1 (25 hours)
HMPL Unit 1	Additional emissions due to CEM heat input delta	8.06	--
HMPL Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	(11.77)	--
HMPL Unit 1 Total		**53.22**	

Additional 2005 NO_x Emissions Information (Continued)

Unit	Description	Tons of NO_x	Comments
HMPL Unit 2	SCR warm up events from forced outages. Total 70 hours warm up combustion without NH_3	32.35	Number of events – 5
HMPL Unit 2	SCR load reduction/low temp events. Total 44 hours low temp combustion without NH_3	8.26	Number of events – 4
HMPL Unit 2	Booster Fan Trips (FGD By-pass Max Potential Emissions) (10)	9.33	Total FGD bypass hours 16
HMPL Unit 2	Additional Emissions Due to Monitor Problem	4.94	Total Monitor Problem Hours (12)
HMPL Unit 2	Additional emissions due to CEM heat input delta	11.42	--
HMPL Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	(0.37)	--
HMPL Unit 2 Total		**65.93**	
Coleman Unit 1	Additional emissions due to CEM heat input delta	70.13	--
Coleman Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	(31.38)	--
Coleman Unit 1 Total		**38.75**	
Coleman Unit 2	Additional emissions due to CEM heat input delta	12.74	--
Coleman Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	(7.21)	--
Coleman Unit 2 Total		**5.53**	

Additional 2005 NO_x Emissions Information (Continued)

Unit	Description	Tons of NO_x	Comments
Coleman Unit 3	Additional emissions due to CEM heat input delta	112.41	--
Coleman Unit 3	Additional emissions due to difference in actual heat rate versus plan heat rate	(28.61)	--
Coleman Unit 3 Total		**83.8**	
Green Unit 1	Additional emissions due to CEM heat input delta	(26.25)	--
Green Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	24.75	--
Green Unit 1 Total		**(1.5)**	
Green Unit 2	Additional emissions due to CEM heat input delta	14.28	--
Green Unit 2	Additional emissions due to difference in actual heat rate versus plan heat rate	23.17	--
Green Unit 2 Total		**37.45**	
Reid Unit 1	Additional emissions due to CEM heat input delta	51.37	--
Reid Unit 1	Additional emissions due to difference in actual heat rate versus plan heat rate	5.98	--
Reid Unit 1 Total		**57.35**	

Appendix E

WKE NO_x Compliance Plan 8A Spreadsheet

WKE System NOx Control Options (Case # 8A)
0.15 lbs/mmBTU

R1&RCT-GasOFA C1,C2,C3-DCS&NN 90% CF; R1 @85% CF; RCT@85% CF

Unit	Firing System	Year 2000 average lbs/mmBtu	Method of Reduction	Capital Cost M$	Annual Capital Catalyst Replacement M$	Annual O&M Fixed (1st yr) M$	Annual O&M Variable M$	Removal Efficiency	Avg. NOx with new equipment	Uncontrolled NOx Season (tons)	Controlled NOx Season (tons)	NOx Removed (tons)
Coleman 1	Front Wall Fired	0.420	OFA/DCS/NN/field devices	7.10	0.000	0.050	0.048	47.00%	0.223	1,120.9	594.1	526.8
Coleman 2	Front Wall Fired	0.428	OFA/DCS/NN/field devices	7.30	0.000	0.050	0.048	47.00%	0.227	1,203.3	637.8	565.6
Coleman 3	Rear Wall Fired	0.417	OFA/DCS/NN/field devices	6.80	0.000	0.050	0.048	47.00%	0.221	1,185.2	628.1	557.0
						350hp*.9(@ $0.025*291 kwh per fan)						
Henderson 1	Rear Wall Fired	0.457	SCR	19.90	0.203	0.136	0.236	90.00%	0.046	1,325.3	132.5	1,192.8
Henderson 2	Rear Wall Fired	0.478	SCR	19.90	0.203	0.136	0.242	90.00%	0.048	1,447.4	144.7	1,302.6
Green 1	Front Wall Fired	0.412	Coal Reburn/DCS/NN/BOP	11.50	0.000	0.075	0.000	50.00%	0.206	1,649.6	824.8	824.8
Green 2	Front Wall Fired	0.422	Coal Reburn/DCS/NN/BOP	13.30	0.000	0.075	0.000	50.00%	0.211	1,713.4	856.7	856.7
					1000 man hrs @ $50/hr + 25K materials							
Wilson 1	Opposed Wall Fired	0.431	SCR / DCS / NN / BOP	52.60	0.656	0.373	0.470	90.00%	0.043	3,802.4	380.2	3,422.1
Reid 1	Front Wall Fired	0.812	50% Gas Fired	3.90	0.000	0.000	6.236	81.71%	0.149	937.7	171.5	766.2
Reid CT	Oil Fired	0.890	Gas fired	0.60	0.000	0.000	5.902	83.15%	0.150	972.7	163.9	808.8
Common				0.70					Totals	15,357.8	4534.4	10,823.4
			summation						Sebree	7,073.3	2,130.3	

NOx Season System Avg.	0.136
NOx Season Emissions (tons)	4,534
NOx Season Credits (tons)	4571
Difference	37

Total annual O&M ($M)= 15.24

LEVELIZED COSTS

Units	20 year levelized $ / ton / year	20 year levelized $ / year	20 year levelized $ / MWH(g) / Season	"Enter Value" (X) years levelized	(X) years levelized $ / ton / year	(X) years levelized $ / year	(X) years levelized $ / MWH(g) / Season
Coleman 1	$894.62	$471,320.71	$0.90		#DIV/0!	#DIV/0!	#DIV/0!
Coleman 2	$851.05	$481,320.71	$0.93		#DIV/0!	#DIV/0!	#DIV/0!
Coleman 3	$819.22	$456,320.71	$0.85		#DIV/0!	#DIV/0!	#DIV/0!
Henderson 1	$1,358.06	$1,619,832.33	$2.97		#DIV/0!	#DIV/0!	#DIV/0!
Henderson 2	$1,248.13	$1,625,832.33	$2.93		#DIV/0!	#DIV/0!	#DIV/0!
Green 1	$821.41	$677,481.06	$0.85		#DIV/0!	#DIV/0!	#DIV/0!
Green 2	$895.84	$767,481.06	$1.00		#DIV/0!	#DIV/0!	#DIV/0!
Wilson 1	$1,246.49	$4,265,672.50	$2.88		#DIV/0!	#DIV/0!	#DIV/0!
Reid 1	$8,393.35	$6,430,867.70	$29.48		#DIV/0!	#DIV/0!	#DIV/0!
Reid CT	$7,334.04	$5,931,994.45	$27.13		#DIV/0!	#DIV/0!	#DIV/0!
		$22,728,123.6	$69.92		#DIV/0!	#DIV/0!	#DIV/0!
System Weighted Average							
Season $ / ton =	$2,100				#DIV/0!		
Season $ / MWHg =	$3.70				#DIV/0!		

NOTES : Capital costs reflect latest vendor negotiations
: First year Fixed O&M from S&L #s
: Fixed O&M escalated 3% per year by compounding to #yrs then dividing by 2.2 to match manual calc of doing each yr additive.
: Variable O&M from S&L #s with Ammonia adjusted to $350/ton and increased to 90% capacity factor (S&L used 85%)
: Annual catalyst cost taken directly from S&L #s

S&L estimated Seasonal O&M	S&L estimated Capitol Costs	# of burners	burner install cost	Unit	Capacity Gross KW	Capacity mmBtu/hr	90% cap factor based on Heat Rates mmBTUs	NOx Season Generation KWH	Thru 2000 CEM Heat Rates (Btu/KWh)	Capacity Factors (%)	Season KWh
(mm$'s)	(mm$s)										
0	0.32	8	520,000	Coleman 1	159,000	1565	5,337,760	525,463,200	10158.2	90	525,463,200
0	0.32	8	520,000	Coleman 2	157,000	1565	5,623,024	518,853,600	10837.4	90	518,853,600
0.61	20.34	8	520,000	Coleman 3	163,000	1586	5,684,177	538,682,400	10552	90	538,682,400
0.59	18.84	16	1,040,000	Henderson 1	165,000	1568	5,799,944	545,292,000	10636.4	90	545,292,000
0.57	19	16	1,040,000	Henderson 2	168,000	1568	6,055,858	555,206,400	10907.4	90	555,206,400
0.71	23.79	24	1,560,000	Green 1	240,000	2660	8,007,583	793,152,000	10095.9	90	793,152,000
0.69	23.27	24	1,560,000	Green 2	232,000	2660	8,120,494	766,713,600	10591.3	90	766,713,600
1.14	37.76	25	1,625,000	Wilson 1	448,000	4585	17,644,459	1,480,550,400	11917.5	90	1,480,550,400
									11728.1		
0	0.8			Reid 1	66,000	834	2,309,581	205,999,200	11211.6	85	205,999,200
0.01	1.56			Reid CT	66,166	787	2,185,924	206,517,319	10584.7	85	206,517,319
						Total	66,768,804	6,136,430,119			6,136,430,119

Appendix F

WKE NO_x Compliance Plan 5B Spreadsheet

WKE System NOx Control Options
0.15 lbs/mmBTU

R1&RCT-GasOFA C1,C2,C3-DCS&NN 90% CF; R1 @85% CF; RCT@85% CF

Unit	Firing System	Year 2000 average lbs/mmBtu	Method of Reduction	Capital Cost M$	Annual Capital Catalyst Replacement M$	Annual O&M Fixed (1st yr) M$	Annual O&M Variable M$	Removal Efficiency	Avg. NOx with new equipment	Uncontrolled NOx Season (tons)	Controlled NOx Season (tons)	NOx Removed (tons)
Coleman 1	Front Wall Fired	0.420	DCS & NN & Field Devices	1.50		0.050		10.00%	0.378	1,120.9	1008.8	112.1
Coleman 2	Front Wall Fired	0.428	DCS & NN & Field Devices	1.50		0.050		10.00%	0.385	1,203.3	1083.0	120.3
Coleman 3	Rear Wall Fired	0.417	DCS & NN & Field Devices	1.50		0.050		10.00%	0.375	1,185.2	1066.6	118.5
Henderson 1	Rear Wall Fired	0.457	SCR / BOP	19.50	0.203	0.136	0.236	90.00%	0.046	1,325.3	132.5	1,192.8
Henderson 2	Rear Wall Fired	0.478	SCR / BOP	19.50	0.203	0.136	0.242	90.00%	0.048	1,447.4	144.7	1,302.6
Green 1	Front Wall Fired	0.412	SCR / DCS / NN / BOP	32.90	0.332	0.185	0.228	90.00%	0.041	1,649.6	165.0	1,484.6
Green 2	Front Wall Fired	0.422	SCR / DCS / NN / BOP	36.30	0.332	0.242	0.213	90.00%	0.042	1,713.4	171.3	1,542.1
Wilson 1	Opposed Wall Fired	0.431	SCR / DCS / NN / BOP	52.60	0.656	0.373	0.470	90.00%	0.043	3,802.4	380.2	3,422.1
Reid 1	Front Wall Fired	0.812	50% Gas Fired	3.90	0.000	0.000	6.236	81.71%	0.149	937.7	171.5	766.2
Reid CT	Oil Fired	0.890	Gas fired	0.60	0.000	0.000	5.902	83.15%	0.150	972.7	163.9	808.8
Common				0.70					Totals	15,357.8	4487.7	10,870.2
Total			summation see note **	170.50			13.527					

NOx Season System Avg.	0.134
NOx Season Emissions (tons)	4,488
NOx Season Credits (tons)	4571
Difference	83

Total annual O&M ($M)= 16.475

** Capital cost adjusted to estimated values June 2001

LEVELIZED COSTS

	20 year levelized	20 year levelized	20 year levelized	"Enter Value"	(X) years levelized	(X) years levelized	(X) years levelized
Units	$ / ton / year	$ / year	$ / MWH(g) / Season	(X) years levelized	$ / ton / year	$ / year	$ / MWH(g) / Season
Coleman 1	$1,278.59	$143,320.71	$0.27		#DIV/0!	#DIV/0!	#DIV/0!
Coleman 2	$1,191.04	$143,320.71	$0.28		#DIV/0!	#DIV/0!	#DIV/0!
Coleman 3	$1,209.30	$143,320.71	$0.27		#DIV/0!	#DIV/0!	#DIV/0!
Henderson 1	$1,341.29	$1,599,832.33	$2.93		#DIV/0!	#DIV/0!	#DIV/0!
Henderson 2	$1,232.78	$1,605,832.33	$2.89		#DIV/0!	#DIV/0!	#DIV/0!
Green 1	$1,655.51	$2,457,786.63	$3.10		#DIV/0!	#DIV/0!	#DIV/0!
Green 2	$1,744.83	$2,690,672.24	$3.51		#DIV/0!	#DIV/0!	#DIV/0!
Wilson 1	$1,246.49	$4,265,672.50	$2.88		#DIV/0!	#DIV/0!	#DIV/0!
Reid 1	$8,393.52	$6,431,000.00	$29.48		#DIV/0!	#DIV/0!	#DIV/0!
Reid CT	$7,334.05	$5,932,000.00	$27.13		#DIV/0!	#DIV/0!	#DIV/0!
Total		$25,412,758.1	$72.74		#DIV/0!	#DIV/0!	#DIV/0!

System
Weighted Average

Season $ / ton =	$2,338				#DIV/0!
Season $ / MWHg =	$4.14				#DIV/0!

NOTES : Capital costs reflect latest vendor negotiations
: First year Fixed O&M from S&L #s
: Fixed O&M escalated 3% per year by compounding to #yrs then dividing by 2.2 to match manual calc of doing each yr additive.
: Variable O&M from S&L #s with Ammonia adjusted to $350/ton and increased to 90% capacity factor (S&L used 85%)
: Annual catalyst cost taken directly from S&L #s

Cap Cost (90%) 30 yr levelized	S&L estimated Fixed O&M	S&L estimated Seasonal O&M	S&L estimated Capitol Costs	# of burners	burner install cost	Unit	Capacity Gross KW	Capacity mmBtu/hr	90% cap factor based on Heat Rates mmBTUs	NOx Season Generation KWH	Thru 2000 CEM Heat Rates (Btu/KWh)	Capacity Factors (%)	Season KWh
$/ton	(mm$'s)	(mm$'s)	(mm$s)										
446		0	0.32	8	520000	Coleman 1	159,000	1565	5,337,760	525,463,200	10158.2	90	525,463,200
416		0	0.32	8	520000	Coleman 2	157,000	1565	5,623,024	518,853,600	10837.4	90	518,853,600
422		0.61	20.34	8	520000	Coleman 3	163,000	1586	5,684,177	538,682,400	10552	90	538,682,400
545		0.59	18.84	16	1040000	Henderson 1	165,000	1568	5,799,944	545,292,000	10636.4	90	545,292,000
499		0.57	19	16	1040000	Henderson 2	168,000	1568	6,055,858	555,206,400	10907.4	90	555,206,400
739		0.71	23.79	24	1560000	Green 1	240,000	2660	8,007,583	793,152,000	10095.9	90	793,152,000
785		0.69	23.27	24	1560000	Green 2	232,000	2660	8,120,494	766,713,600	10591.3	90	766,713,600
512		1.14	37.76	25	1625000	Wilson 1	448,000	4585	17,644,459	1,480,550,400	11917.5	90	1,480,550,400
170		0	0.8			Reid 1	66,000	834	2,309,581	205,999,200	11211.6	85	205,999,200
25		0.01	1.56			Reid CT	66,166	787	2,185,924	206,517,319	10584.7	85	206,517,319
								Total	66,768,804	6,136,430,119			6,136,430,119

Appendix G

2004 and 2005 WKE NO_x Actuals Compared to Budget Spreadsheets

2004 NOx Actuals Compared To Budget

MAY

	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	85,063	4.0	0.0000	76,333	0.0	0.0000	(8,730)	(4.0)	-10%	-100%
Coleman 2	76,576	3.0	0.0000	94,959	5.8	0.0001	18,383	2.8	24%	93%
Coleman 3	28,948	1.0	0.0000	43,692	5.2	0.0001	14,744	4.2	51%	420%
Henderson 1	72,688	1.0	0.0000	112,445	7.5	0.0001	39,757	6.5	55%	650%
Henderson 2	69,039	1.0	0.0000	78,676	7.1	0.0001	9,637	6.1	14%	610%
Green 1	169,781	6.0	0.0000	171,471	3.2	0.0000	1,690	(2.8)	1%	-47%
Green 2	166,455	6.0	0.0000	136,711	6.0	0.0000	(29,744)	0.0	-18%	0%
Reid 1	29,060	3.0	0.0001	23,397	0.0	0.0000	(5,663)	(3.0)	-19%	-100%
Reid CT	0	0.0		1,511	7.2		1,511	7.2		
Wilson 1	311,247	3.0	0.0000	314,103	3.1	0.0000	2,856	0.1	1%	3%
Totals	1,008,857	28.0	0.0000	1,053,298	45.1	0.0000	44,441	17.1	4%	61%

JUNE

	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	74,369	97.0	0.0013	76,167	125.1	0.0016	1,798	28.1	2%	29%
Coleman 2	72,047	95.0	0.0013	96,202	147.4	0.0015	24,155	52.4	34%	55%
Coleman 3	81,330	107.0	0.0013	88,632	136.2	0.0015	7,302	29.2	9%	27%
Henderson 1	71,278	25.0	0.0004	107,584	65.8	0.0006	36,306	40.8	51%	163%
Henderson 2	69,888	25.0	0.0004	104,698	53.6	0.0005	34,810	28.6	50%	114%
Green 1	152,059	166.0	0.0011	143,025	140.8	0.0010	(9,034)	(25.2)	-6%	-15%
Green 2	149,089	162.0	0.0011	160,004	163.9	0.0010	10,915	1.9	7%	1%
Reid 1	0	0.0		1,222	5.4	0.0044	1,222	5.4		
Reid CT	0	0.0		3,657	39.4		3,657	39.4		
Wilson 1	301,218	78.0	0.0003	256,619	120.0	0.0005	(44,599)	42.0	-15%	54%
Totals	971,278	755.0	0.0008	1,037,810	997.6	0.0010	66,532	242.6	7%	32%

JULY

	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	84,474	110.0	0.0013	75,052	120.8	0.0016	(9,422)	10.8	-11%	10%
Coleman 2	81,545	107.0	0.0013	88,009	138.4	0.0016	6,464	31.4	8%	29%
Coleman 3	92,719	121.0	0.0013	90,662	130.6	0.0014	(2,057)	9.6	-2%	8%
Henderson 1	72,106	26.0	0.0004	98,894	38.6	0.0004	26,788	12.6	37%	48%
Henderson 2	71,040	26.0	0.0004	105,058	67.0	0.0006	34,018	41.0	48%	158%
Green 1	157,120	171.0	0.0011	165,813	170.5	0.0010	8,693	(0.5)	6%	0%
Green 2	155,166	168.0	0.0011	166,101	175.0	0.0011	10,935	7.0	7%	4%
Reid 1	0	0.0		13,459	32.4	0.0024	13,459	32.4		
Reid CT	0	0.0		(93)	0.0		(93)	0.0		
Wilson 1	309,811	81.0	0.0003	299,497	120.6	0.0004	(10,314)	39.6	-3%	49%
Totals	1,023,981	810.0	0.0008	1,102,452	993.9	0.0009	78,471	183.9	8%	23%

Note: Generation Values are Gross

[redacted]

	Budget			Actuals			Difference From Budget		Generation Over/(Under)	NOx Tons Over/(Under)
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons		
Coleman 1	79,011	103.0	0.0013	91,605	143.5	0.0016	12,594	40.5	16%	39%
Coleman 2	79,716	105.0	0.0013	84,372	128.1	0.0015	4,656	23.1	6%	22%
Coleman 3	89,268	117.0	0.0013	88,237	129.8	0.0015	(1,031)	12.8	-1%	11%
Henderson 1	71,870	26.0	0.0004	71,374	34.8	0.0005	(496)	8.8	-1%	34%
Henderson 2	67,573	25.0	0.0004	104,975	44.4	0.0004	37,402	19.4	55%	78%
Green 1	155,435	169.0	0.0011	163,221	178.3	0.0011	7,786	9.3	5%	6%
Green 2	152,479	166.0	0.0011	169,622	179.7	0.0011	17,143	13.7	11%	8%
Reid 1	0	0.0		2,806	7.0	0.0025	2,806	7.0		
Reid CT	0	0.0		(35)	0.0		(35)	0.0		
Wilson 1	311,247	81.0	0.0003	294,811	89.3	0.0003	(16,436)	8.3	-5%	10%
Totals	1,006,599	792.0	0.0008	1,070,988	934.9	0.0009	64,389	142.9	6%	18%

[redacted]

	Budget			Actuals			Difference From Budget		Generation Over/(Under)	NOx Tons Over/(Under)
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons		
Coleman 1	70,949	93.0	0.0013	81,624	125.1	0.0015	10,675	32.1	15%	35%
Coleman 2	72,752	97.0	0.0013	86,100	123.8	0.0014	13,348	26.8	18%	28%
Coleman 3	80,367	106.0	0.0013	91,036	136.9	0.0015	10,669	30.9	13%	29%
Henderson 1	71,040	25.0	0.0004	59,273	52.5	0.0009	(11,767)	27.5	-17%	110%
Henderson 2	69,540	25.0	0.0004	105,455	41.5	0.0004	35,915	16.5	52%	66%
Green 1	146,291	160.0	0.0011	154,876	156.0	0.0010	8,585	(4.0)	6%	-3%
Green 2	145,737	158.0	0.0011	150,942	158.1	0.0010	5,205	0.1	4%	0%
Reid 1	0	0.0		(1,363)	0.0	0.0000	(1,363)	0.0		
Reid CT	0	0.0		0	0.0		0	0.0		
Wilson 1	301,218	78.0	0.0003	281,831	87.5	0.0003	(19,387)	9.5	-6%	12%
Totals	957,894	742.0	0.0008	1,009,774	881.4	0.0009	51,880	139.4	5%	19%

YEAR-TO-DATE THROUGH SEPTEMBER

	Budget			Actuals			Difference From Budget		Generation Over/(Under)	NOx Tons Over/(Under)
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons		
Coleman 1	393,866	407	0.0010	400,781	515	0.0013	6,915	107.5	2%	26%
Coleman 2	382,636	407	0.0011	449,642	544	0.0012	67,006	136.5	18%	34%
Coleman 3	372,632	452	0.0012	402,259	539	0.0013	29,627	86.7	8%	19%
Henderson 1	358,982	103	0.0003	449,570	199	0.0004	90,588	96.2	25%	93%
Henderson 2	347,080	102	0.0003	498,862	214	0.0004	151,782	111.6	44%	109%
Green 1	780,686	672	0.0009	798,406	649	0.0008	17,720	(23.2)	2%	-3%
Green 2	768,926	660	0.0009	783,380	683	0.0009	14,454	22.7	2%	3%
Reid 1	29,060	3	0.0001	39,521	45	0.0011	10,461	41.8	36%	1393%
Reid CT	0	0		5,040	47		5,040	46.6		
Wilson 1	1,534,741	321	0.0002	1,446,861	421	0.0003	(87,880)	99.5	-6%	31%
Totals	4,968,609	3127.0	0.0006	5,274,322	3852.9	0.0007	305,713	725.9	6%	23%

Note: Generation Values are Gross

2004 NOx Plan Review thru Sept.xls
Printed 1/18/2006

2005 NOx Actuals Compared To Budget

	MAY									
	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	69,404	107.0	0.0015	86,223	137.1	0.0016	16,819	30.1	24%	28%
Coleman 2	64,052	99.0	0.0015	81,799	122.2	0.0015	17,747	23.2	28%	23%
Coleman 3	93,623	141.0	0.0015	92,024	134.1	0.0015	(1,599)	(6.9)	-2%	-5%
Henderson 1	104,111	26.0	0.0002	106,622	44.5	0.0004	2,511	18.5	2%	71%
Henderson 2	98,884	25.0	0.0003	84,891	45.2	0.0005	(13,993)	20.2	-14%	81%
Green 1	155,754	170.0	0.0011	178,062	174.7	0.0010	22,308	4.7	14%	3%
Green 2	134,820	149.0	0.0011	164,141	170.6	0.0010	29,321	21.6	22%	14%
Reid 1	11,381	32.0	0.0028	(1,495)	0.0	0.0000	(12,876)	(32.0)	-113%	-100%
Reid CT	0	0.0		(54)	0.0		(54)	0.0	0%	0%
Wilson 1	323,347	84.0	0.0003	320,983	92.8	0.0003	(2,364)	8.8	-1%	10%
Totals	1,055,376	833.0	0.0008	1,113,195	921.2	0.0008	57,819	88.2	5%	11%

	JUNE									
	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	67,253	103.0	0.0015	88,580	151.2	0.0017	21,327	48.2	32%	47%
Coleman 2	64,762	100.0	0.0015	74,564	116.1	0.0016	9,802	16.1	15%	16%
Coleman 3	83,101	125.0	0.0015	89,954	142.7	0.0016	6,853	17.7	8%	14%
nderson 1	100,913	26.0	0.0003	109,107	48.0	0.0004	8,194	22.0	8%	85%
Henderson 2	98,944	24.0	0.0002	105,909	33.5	0.0003	6,965	9.5	7%	40%
Green 1	151,433	165.0	0.0011	157,653	157.6	0.0010	6,220	(7.4)	4%	-4%
Green 2	146,808	162.0	0.0011	162,985	182.7	0.0011	16,177	20.7	11%	13%
Reid 1	7,228	20.0	0.0028	34,983	92.9	0.0027	27,755	72.9	384%	365%
Reid CT	0	0.0		(57)	0.0		(57)	0.0	0%	0%
Wilson 1	309,808	81.0	0.0003	299,519	66.9	0.0002	(10,289)	(14.1)	-3%	-17%
Totals	1,030,250	806.0	0.0008	1,123,197	991.6	0.0009	92,947	185.6	9%	23%

	JULY									
	Budget			Actuals			Difference From Budget		Generation	NOx Tons
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Over/(Under)	Over/(Under)
Coleman 1	75,665	115.0	0.0015	76,791	126.6	0.0016	1,126	11.6	1%	10%
Coleman 2	73,153	112.0	0.0015	81,060	129.0	0.0016	7,907	17.0	11%	15%
Coleman 3	97,889	147.0	0.0015	87,541	158.9	0.0018	(10,348)	11.9	-11%	8%
Henderson 1	103,961	28.0	0.0003	110,031	40.5	0.0004	6,070	12.5	6%	45%
Henderson 2	102,423	27.0	0.0003	109,030	41.1	0.0004	6,607	14.1	6%	52%
Green 1	181,700	197.0	0.0011	178,890	185.7	0.0010	(2,810)	(11.3)	-2%	-6%
Green 2	175,282	192.0	0.0011	172,423	185.5	0.0011	(2,859)	(6.5)	-2%	-3%
Reid 1	28,122	79.0	0.0028	30,792	105.3	0.0034	2,670	26.3	9%	33%
Reid CT	0	0.0		8	0.2		8	0.2	0%	0%
lson 1	324,206	84.0	0.0003	327,181	81.0	0.0002	2,975	(3.0)	1%	-4%
Totals	1,162,401	981.0	0.0008	1,173,747	1053.8	0.0009	11,346	72.8	1%	7%

Note: Generation Values are Gross

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AUGUST

	Budget			Actuals			Difference From Budget			
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Generation Over/(Under)	NOx Tons Over/(Under)
Coleman 1	72,914	111.0	0.0015	96,964	157.7	0.0016	24,050	46.7	33%	42%
Coleman 2	70,249	108.0	0.0015	92,729	144.7	0.0016	22,480	36.7	32%	34%
Coleman 3	86,044	130.0	0.0015	92,252	176.4	0.0019	6,208	46.4	7%	36%
Henderson 1	104,094	28.0	0.0003	103,815	43.8	0.0004	(279)	15.8	0%	56%
Henderson 2	97,870	27.0	0.0003	110,307	39.7	0.0004	12,437	12.7	13%	47%
Green 1	176,690	192.0	0.0011	183,498	195.2	0.0011	6,808	3.2	4%	2%
Green 2	170,816	187.0	0.0011	170,042	192.5	0.0011	(774)	5.5	0%	3%
Reid 1	22,551	64.0	0.0028	36,797	131.0	0.0036	14,246	67.0	63%	105%
Reid CT	0	0.0		2,040	22.5		2,040	22.5	0%	0%
Wilson 1	324,206	84.0	0.0003	245,247	86.6	0.0004	(78,959)	2.6	-24%	3%
Totals	1,125,434	931.0	0.0008	1,133,691	1190.1	0.0010	8,257	259.1	1%	28%

SEPTEMBER

	Budget			Actuals			Difference From Budget			
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Generation Over/(Under)	NOx Tons Over/(Under)
Coleman 1	62,330	96.0	0.0015	91,320	164.4	0.0018	28,990	68.4	47%	71%
Coleman 2	56,055	87.0	0.0016	75,708	124.0	0.0016	19,653	37.0	35%	43%
Coleman 3	88,336	133.0	0.0015	88,032	144.5	0.0016	(304)	11.5	0%	9%
Henderson 1	100,913	26.0	0.0003	114,272	36.2	0.0003	13,359	10.2	13%	39%
Henderson 2	98,783	24.0	0.0002	101,269	44.9	0.0004	2,486	20.9	3%	87%
een 1	149,496	163.0	0.0011	166,156	174.3	0.0010	16,660	11.3	11%	7%
Green 2	144,138	159.0	0.0011	132,525	150.3	0.0011	(11,613)	(8.7)	-8%	-5%
Reid 1	16,491	47.0	0.0029	29,179	103.5	0.0035	12,688	56.5	77%	120%
Reid CT	0	0.0		(106)	0.0		(106)	0.0	0%	0%
Wilson 1	311,917	81.0	0.0003	314,376	96.6	0.0003	2,459	15.6	1%	19%
Totals	1,028,459	816.0	0.0008	1,112,731	1038.7	0.0009	84,272	222.7	8%	27%

YEAR-TO-DATE THROUGH SEPTEMBER

	Budget			Actuals			Difference From Budget			
	Generation	Tons	Tons/MWH	Generation	Tons	Tons/MWH	Generation	Tons	Generation Over/(Under)	NOx Tons Over/(Under)
Coleman 1	347,566	532	0.0015	439,878	737	0.0017	92,312	205.0	27%	39%
Coleman 2	328,271	506	0.0015	405,860	636	0.0016	77,589	130.0	24%	26%
Coleman 3	448,993	676	0.0015	449,803	757	0.0017	810	80.6	0%	12%
Henderson 1	513,992	134	0.0003	543,847	213	0.0004	29,855	79.0	6%	59%
Henderson 2	496,904	127	0.0003	511,406	204	0.0004	14,502	77.4	3%	61%
Green 1	815,073	887	0.0011	864,259	888	0.0010	49,186	0.5	6%	0%
Green 2	771,864	849	0.0011	802,116	882	0.0011	30,252	32.6	4%	4%
Reid 1	85,773	242	0.0028	130,256	433	0.0033	44,483	190.7	52%	79%
Reid CT	0	0		1,831	23		1,831	22.7	0%	0%
Wilson 1	1,593,484	414	0.0003	1,507,306	424	0.0003	(86,178)	9.9	-5%	2%
otals	5,401,920	4367.0	0.0008	5,656,561	5195.4	0.0009	254,641	828.4	5%	19%

Note: Generation Values are Gross

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Appendix H

Historical 2000 through 2005
Forced Outage Data Spreadsheets

HISTORICAL OTAG SEASON FORCED OUTAGE HOURS/UNIT STARTS

	Historical OTAG Season Forced Outage Hours (1)						
	2005	2004	2003	2002	2001	2000	2000-05 Avg
Coleman 1	180.98	168.53	364.42	220.02	146.67	103.20	197.30
Coleman 2	184.88	157.17	122.62	30.17	65.50	178.35	123.11
Coleman 3	104.25	82.88	131.83	251.12	182.47	33.08	130.94
Green 1	67.18	199.05	143.92	233.68	75.93	180.62	150.06
Green 2	45.03	50.30	85.63	12.62	74.83	149.03	69.58
HMPL 1	186.30	140.45	114.58	149.72	180.87	163.88	155.97
HMPL 2	53.45	203.37	217.05	345.45	368.57	61.37	208.21
Reid	372.52	22.15	226.85	347.53	309.18	52.82	221.84
Wilson	250.80	294.38	70.87	187.77	162.02	105.75	178.60

	Historical OTAG Season Number of Unit Starts (from Forced Outages) (1)						
	2005	2004	2003	2002	2001	2000	2000-05 Avg
Coleman 1	4	6	7	7	3	1	4.67
Coleman 2	4	3	5	2	2	2	3.00
Coleman 3	4	5	6	7	3	2	4.50
Green 1	3	7	9	9	2	6	6.00
Green 2	6	3	5	2	11	4	5.17
HMPL 1	4	3	6	2	3	7	4.17
HMPL 2	1	5	5	5	4	2	3.67
Reid	8	4	9	5	8	6	6.67
Wilson	9	5	7	5	3	2	5.17

HISTORICAL OTAG SEASON FORCED OUTAGE HOURS/UNIT STARTS

	Historical OTAG Season Forced Outage Hours/Unit Start (1)						
	2005	2004	2003	2002	2001	2000	2000-05 Avg
Coleman 1	45.25	28.09	52.06	31.43	48.89	103.20	42.28
Coleman 2	46.22	52.39	24.52	15.08	32.75	89.18	41.04
Coleman 3	26.06	16.58	21.97	35.87	60.82	16.54	29.10
Green 1	22.39	28.44	15.99	25.96	37.97	30.10	25.01
Green 2	7.51	16.77	17.13	6.31	6.80	37.26	13.47
HMPL 1	46.58	46.82	19.10	74.86	60.29	23.41	37.43
HMPL 2	53.45	40.67	43.41	69.09	92.14	30.68	56.78
Reid	46.56	5.54	25.21	69.51	38.65	8.80	33.28
Wilson	27.87	58.88	10.12	37.55	54.01	52.88	34.57

(1) Based on data from WKE Production Outage Reports.

HISTORICAL OTAG SEASON/ANNUAL OUTAGE HOURS

	HISTORICAL OTAG Season Forced Outage Hours/Total Annual Forced Outage Hours [1]						
	2005	2004	2003	2002	2001	2000	2000-05 Avg
Coleman 1	31.38%	29.67%	67.20%	53.08%	83.87%	43.43%	51.44%
Coleman 2	97.88%	60.08%	27.94%	16.72%	37.53%	34.04%	45.70%
Coleman 3	45.61%	29.39%	32.66%	43.38%	45.34%	14.05%	35.07%
Green 1	51.62%	53.20%	73.23%	78.55%	59.46%	45.23%	60.22%
Green 2	32.82%	20.71%	63.42%	13.29%	57.96%	46.98%	39.20%
HMPL 1	70.41%	36.80%	20.64%	25.15%	50.85%	49.85%	42.28%
HMPL 2	20.13%	34.57%	33.32%	38.18%	45.92%	19.94%	32.01%
Reid	57.61%	10.93%	24.16%	50.77%	43.09%	30.40%	36.16%
Wilson	49.94%	58.45%	5.78%	31.35%	76.60%	47.08%	44.87%

[1] Based on data from WKE Production Outage Reports.

2005 Forced Outage Hours

Outage Hours - 2005

2005 Outages	Coleman Unit 1 FO(1)	Date	Type	PO(2)	Coleman Unit 2 FO(1)	Date	Type	PO(2)	Coleman Unit 3 FO(1)	Date	Type	PO(2)
1	---	2/25	PO	553.70	---	3/18	PO	167.13	38.93	1/20	UO1	---
2	---	3/19	PO	6.25	---	3/26	PO	6.27	2.15	2/24	UO1	---
3	5.73	3/20	UO4	—	36.78	6/8	UO1	—	10.27	2/24	UO1	---
4	50.35	4/8	UO2	—	83.53	7/13	UO1	—	2.57	3/17	UO1	---
5	49.38	5/18	UO1	—	32.05	9/25	UO4	—	---	3/25	PO	159.60
6	3.28	6/15	UO1	—	32.52	9/29	UO2	—	---	4/1	PO	2.45
7	38.68	7/9	UO2	—	4.00	10/1	UO1	---	1.52	5/21	UO1	—
8	89.63	7/13	UO1	—	---	---	---	---	1.48	7/3	UO1	—
9	2.03	11/11	UO1	---	---	---	---	---	77.62	7/29	UO4	—
10	66.32	11/25	UO2	---	---	---	---	---	23.63	9/4	UO4	---
11	10.85	12/1	UO4	---	---	---	---	---	10.15	10/15	UO1	---
12	245.63	12/14	UO2	---	---	---	---	---	49.20	12/27	UO2	---
13	12.38	12/25	UO1	---	---	---	---	---	11.05	12/29	UO1	---
14	2.47	12/25	UO4	---	---	---	---	---	---	---	---	---
15	---	---	---	---	---	---	---	---	---	---	---	---
16	---	---	---	---	---	---	---	---	---	---	---	---
17	---	---	---	---	---	---	---	---	---	---	---	---
18	---	---	---	---	---	---	---	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	576.75			559.95	188.88			173.40	228.57			162.05

2005 Outages	Green Unit 1 FO(1)	Date	Type	PO(2)	Green Unit 2 FO(1)	Date	Type	PO(2)	HMPL Unit 1 FO(1)	Date	Type	PO(2)
1	30.60	2/11	UO4	---	43.07	12/31	UO4	---	6.85	1/3	UO1	—
2	1.87	2/13	UO4	---	6.88	1/5	UO1	---	13.17	2/1	UO2	---
3	1.30	3/29	UO1	---	34.83	2/5	UO4	---	53.45	3/11	UO4	---
4	0.83	3/29	UO1	---	2.62	3/6	UO1	---	50.77	5/28	UO4	---
5	6.40	5/16	UO1	—	0.93	3/6	UO1	---	45.48	7/1	UO4	—
6	50.32	6/10	UO4	—	1.78	3/20	UO1	---	44.20	8/10	UO1	—
7	8.90	9/7	UO2	—	---	4/1	BPO	612.17	45.85	8/26	UO1	---
8	1.57	9/29	UO1/PO	54.50	---	4/27	EPO	2.03	4.07	10/7	UO1	---
9	0.48	10/2	UO1	—	---	4/27	EPO	0.65	---	10/8	BPO	1,625.13
10	7.80	10/2	UO3	---	---	4/27	EPO	0.35	---	12/14	EPO	1.98
11	10.82	10/27	UO1	---	---	4/27	EPO	2.17	---	12/15	EPO	6.57
12	0.95	10/27	UO1	---	---	4/27	EPO	0.98	0.75	12/15	UO1	---
13	5.05	11/23	UO1	---	2.68	5/8	UO1	—	---	---	---	---
14	3.27	11/27	UO1	---	21.17	5/25	UO2	—	---	---	---	---
15	---	---	---	---	1.02	6/18	UO1	---	---	---	---	---
16	---	---	---	---	5.42	8/30	UO1	—	---	---	---	---
17	---	---	---	---	---	9/23	BPO	120.67	---	---	---	---
18	---	---	---	---	11.40	9/29	UO2	—	---	---	---	---
19	---	---	---	---	3.35	9/29	UO1	—	---	---	---	---
20	---	---	---	---	2.05	10/12	UO1	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	130.15			54.50	137.20			739.22	264.58			1,633.68

2005 Outages	HMPL Unit 2 FO(1)	Date	Type	PO(2)	Reid FO(1)	Date	Type	PO(2)	Wilson FO(1)	Date	Type	PO(2)
1	5.30	1/28	UO1	---	59.83	1/1	UO2	---	38.13	2/23	UO4	---
2	19.63	1/28	UO1	---	7.08	1/4	UO1	---	9.63	4/19	UO1	---
3	51.92	2/18	UO4	---	---	1/9	RS	104.38	11.48	4/28	UO1	---
4	54.75	3/1	UO2	---	3.87	2/27	UO1	—	7.17	5/10	UO1	—
5	28.93	3/20	UO2	---	41.63	3/15	UO2	---	14.02	5/14	UO1	---
6	—	5/20	BPO	181.48	—	4/30	RS	795.72	40.57	6/3	UO4	---
7	53.45	9/16	UO4	---	1.60	6/17	UO1	—	3.37	7/5	UO1	—
8	51.55	12/2	UO4	---	0.98	6/17	UO1	—	36.30	8/2	UO1	---
9	---	---	---	---	65.00	7/1	UO2	—	30.37	8/9	UO1	---
10	---	---	---	---	91.50	7/19	UO4	—	66.62	8/10	UO1	—
11	---	---	---	---	25.62	8/4	UO4	---	45.48	8/24	UO1	—
12	---	---	---	---	8.37	8/23	UO1	—	6.92	9/21	UO4	---
13	---	---	---	---	172.45	9/9	UO4	—	26.75	10/9	UO3	---
14	---	---	---	---	7.00	9/17	UO1	—	21.13	10/22	UO3	---
15	---	---	---	---	---	11/4	RS	181.88	119.13	11/11	UO3	---
16	---	---	---	---	---	11/19	RS	104.30	4.45	11/19	UO1	---
17	---	---	---	---	6.73	11/26	UO3	---	20.67	11/23	UO1	---
18	---	---	---	---	37.67	12/5	RS/ UO3	35.22	---	---	---	---
19	---	---	---	---	58.37	12/10	UO3	---	---	---	---	---
20	---	---	---	---	58.90	12/25	UO1 /RS	88.00	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	265.53			181.48	646.60			1,309.50	502.18			

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).
(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

OTAG Season Outage Hours:	Coleman Unit 1 FO(1)	PO(2)	Coleman Unit 2 FO(1)	PO(2)	Coleman Unit 3 FO(1)	PO(2)
	49.38	—	36.78	—	1.52	—
	3.28	—	83.53	—	1.48	—
	38.68	—	32.05	—	77.62	---
	89.63	—	32.52	---	23.63	---
	180.98		184.88	-	104.25	
Unit Starts	4	0	4	0	4	0
Hrs/Unit Start	45.25	.	46.22	.	26.06	.
% OTAG Outage/Total Outage Hours	31.38%	0.00%	97.88%	0.00%	45.61%	0.00%

OTAG Season Outage Hours:	Green Unit 1 FO(1)	PO(2)	Green Unit 2 FO(1)	PO(2)	HMPL Unit 1 FO(1)	PO(2)
	6.40	---	2.68	---	50.77	—
	50.32	—	21.17	—	45.48	—
	8.90	—	1.02	—	44.20	—
	1.57	26.00	5.42	—	45.85	—
			—	120.67		
			11.40	—		
			3.35	---		
	67.18	26.00	45.03	120.67	186.30	-
Unit Starts	3	0	6		4	0
Hrs/Unit Start	22.39	.	7.51	120.67	46.58	.
% OTAG Outage/Total Outage Hours	51.62%	47.71%	32.82%	16.32%	70.41%	0.00%

OTAG Season Outage Hours:	HMPL Unit 2 FO(1)	PO(2)	Reid FO(1)	PO(2)	Wilson FO(1)	PO(2)
	---	181.48	—	794.88	7.17	—
	53.45	—	1.60	—	14.02	—
			0.98	—	40.57	—
			65.00	—	3.37	---
			91.50	—	36.30	---
			25.62	—	30.37	—
			8.37	—	66.62	—
			172.45	—	45.48	—
			7.00	---	6.92	—
	53.45	181.48	372.52	794.88	250.80	-
Unit Starts	1	1	8		9	0
Hrs/Unit Start	53.45	181.48	46.56	794.88	27.87	.
% OTAG Outage/Total Outage Hours	20.13%	100.00%	57.61%	60.70%	49.94%	0.00%

2004 Forced Outage Hours

Outage Hours - 2004

2004	Coleman Unit 1				Coleman Unit 2				Coleman Unit 3				Green Unit 1			
Outages	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	6.68	1/2	UO4	---	35.33	1/17	UO4	---	25.28	1/15	UO4	---	0.97	1/6	UO1	---
2	1.57	1/3	UO1	---	56.07	3/14	UO2	---	4.75	1/19	UO1	---	31.18	3/1	UO1	---
3	46.33	1/23	UO4	---	---	4/9	PO	502.28	13.03	1/23	UO3	---	42.38	3/26	UO4	---
4	36.50	3/27	UO2	---	9.02	5/1	UO4	---	1.62	3/15	UO1	---	1.80	5/23	UO1	---
5	20.30	4/6	UO4	---	8.55	5/1	UO1	---	55.50	3/23	UO4	---	10.87	5/31	UO2	---
6	1.68	4/11	UO1	---	1.32	5/5	UO1	---	---	5/1	PO	418.00	41.08	6/4	UO4	---
7	48.73	4/29	UO2	---	28.72	7/16	UO4	---	43.43	6/20	UO1	---	41.27	6/13	UO2	---
8	11.92	5/10	UO4	---	26.47	8/10	UO4	---	1.60	6/22	UO1	---	7.82	7/9	UO1	---
9	---	5/25	PO	255.92	34.63	8/13	UO1	---	22.53	6/26	UO4	---	50.07	8/2	UO1	---
10	20.37	6/5	UO1	---	57.18	9/28	UO4	---	3.00	7/23	UO1	---	34.38	9/16	UO1	---
11	37.22	7/4	UO4	---	2.32	12/16	UO1	---	12.32	8/13	UO1	---	41.03	9/30	UO3	---
12	6.60	8/13	UO1	---	---	---	---	---	1.77	10/15	UO1	---	19.92	10/4	UO1	---
13	87.12	9/13	UO4	---	---	---	---	---	42.79	11/12	UO3	---	30.90	10/9	UO1	---
14	79.48	10/2	UO4	---	---	---	---	---	1.72	11/14	UO2	---	20.52	10/29	UO1	---
15	40.73	10/31	UO4	---	---	---	---	---	4.12	11/14	UO1	---	---	11/14	BPO	200.50
16	23.50	11/6	UO4	---	---	---	---	---	43.12	11/29	UO4	---	---	---	---	---
17	22.02	11/13	UO3	---	---	---	---	---	5.48	12/8	UO1	---	---	---	---	---
18	16.05	11/15	UO4	---	---	---	---	---	---	---	---	---	---	---	---	---
19	8.18	12/22	UO1	---	---	---	---	---	---	---	---	---	---	---	---	---
20	2.93	12/23	UO1	---	---	---	---	---	---	---	---	---	---	---	---	---
21	10.82	12/23	UO1	---	---	---	---	---	---	---	---	---	---	---	---	---
22	39.07	12/29	UO4	---	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Total	568.00			255.92	261.60			502.28	282.05			418.00	374.18			200.50
Total w/o HMPL 1 August 2004 boiler event.																

2004	Green Unit 2				HMPL Unit 1				HMPL Unit 2				Reid				Wilson			
Outages	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	1.98	2/18	UO1	---	58.90	1/6	UO2	---	72.57	1/17	UO3	---	---	12/23	RS	93.22	155.35	3/7	UO1	---
2	25.83	3/12	UO1	---	---	2/15	BPO	165.43	43.53	2/13	UO2	---	8.00	2/19	UO4	---	14.47	4/14	UO1	---
3	16.65	4/1	UO2	---	4.23	2/22	UO1	---	---	2/22	BPO	915.52	4.65	3/1	UO1	---	34.45	5/27	UO1	---
4	0.58	4/2	UO1	---	50.33	4/16	UO1	---	27.37	4/11	UO1	--- (3)	6.53	3/31	UO4	---	42.00	6/2	UO1	---
5	45.77	4/24	UO4	---	8.50	6/8	UO1	---	7.85	4/12	UO1	--- (3)	15.07	5/11	UO3	---	8.75	6/4	UO1	---
6	---	5/19	BPO	131.70	72.98	7/5	UO1	---	74.60	4/16	UO4	---	3.60	5/16	UO1	---	61.12	6/15	UO1	---
7	6.30	6/25	UO1	---	58.97	8/21	UO1	---	1.50	4/26	UO1	---	---	5/29	BPO	731.10	32.12	7/19	UO4	---
8	42.53	9/18	UO4	---	515.28	8/23	UO2	---	73.28	5/2	UO1	---	---	6/28	EPO	3.82	57.83	8/25	UO1	---
9	1.37	9/26	UO1	---	11.93	11/10	UO1	---	33.48	5/14	UO4	---	---	6/29	EPO	1.13	58.12	9/27	UO1	---
10	1.47	9/30	UO1	---	62.27	11/22	UO1	---	64.12	5/17	UO2	---	---	6/30	EPO	5.20	14.22	10/14	UO1	---
11	5.47	11/5	UO4	---	52.32	12/13	UO1	---	3.33	5/20	UO1	---	---	6/30	EPO	4.25	---	10/23	PO	499.75
12	51.85	11/26	UO4	---	1.22	12/16	UO1	---	29.15	8/30	UO1	---	---	7/1	RS	123.98	1.97	11/12	UO1	---
13	43.07	12/31	UO4	---	---	---	---	---	20.15	10/3	UO4	---	1.58	7/8	UO1	---	12.25	11/13	UO1	---
14	---	---	---	---	---	---	---	---	24.67	12/4	UO4	---	1.90	7/8	UO1	---	5.22	12/19	UO1	---
15	---	---	---	---	---	---	---	---	100.17	12/10	UO4 /SF	---	---	7/10	RS	16.25	5.80	12/21	UO1	---
16	---	---	---	---	---	---	---	---	12.35	12/17	UO4	---	---	7/16	RS	64.90	---	---	---	---
17	---	---	---	---	---	---	---	---	---	---	---	---	---	7/22	RS	264.65	---	---	---	---
18	---	---	---	---	---	---	---	---	---	---	---	---	---	8/4	RS	1,394.50	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---	---	10/1	RS	510.35	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---	42.23	11/6	UO1	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---	48.40	11/22	UO1 /RS	116.93	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---	70.73	12/13	UO2	---	---	---	---	---
Total	242.87			131.70	896.93			165.43	588.32			915.52	202.70			3,332.28	503.65			499.75
Total w/o HMPL 1 August 2004 boiler event.					381.65	(4)														

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).

(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

(3) Labeled on the outage sheets as BPO but appears to be tripping episode. Both were due to turbine control problems. The first one said the unit tripped on reverse current when it was backed down to 3 MW. The second one (7.85 hour outage) was manually tripped.

(4) HMPL Unit 1 August 23, 2004 boiler event was excluded from the calculon of OTAG unit starts and % OTAG Forced Outages/Annual Forced Outages. The boiler event is assumed to be a "one time event".

	Coleman Unit 1 FO(1)	Coleman Unit 1 PO(2)	Coleman Unit 2 FO(1)	Coleman Unit 2 PO(2)	Coleman Unit 3 FO(1)	Coleman Unit 3 PO(2)	Green Unit 1 FO(1)	Green Unit 1 PO(2)	Green Unit 2 FO(1)	Green Unit 2 PO(2)	HMPL Unit 1 FO(1)	HMPL Unit 1 PO(2)	HMPL Unit 2 FO(1)	HMPL Unit 2 PO(2)	Reid FO(1)	Reid PO(2)	Wilson FO(1)	Wilson PO(2)
OTAG Season Outage Hours:	5.32	---	9.02	---	---	418.00	1.80	---	---	131.70	8.50	---	73.28	---	15.07	731.10	34.45	---
	11.92	---	8.55	---	43.43	---	10.87	---	6.30	---	72.98	---	33.48	---	3.60	3.82	42.00	---
	---	255.92	1.32	---	1.60	---	41.08	---	42.53	---	58.97	---	64.12	---	1.58	1.13	8.75	---
	20.37	---	28.72	---	22.53	---	41.27	---	1.37	---	(4)	---	3.33	---	1.90	5.20	61.12	---
	37.22	---	26.47	---	3.00	---	7.82	---	0.10	---			29.15	---		4.25	32.12	---
	6.60	---	34.63	---	12.32	---	50.07	---								123.98	57.83	---
	87.12	---	49.47	---			34.38	---								18.25	58.12	---
							11.77	---								64.90		
																264.65		
																1,394.50		
TOTAL	168.53	255.92	157.17		82.88	418.00	199.05		50.30	131.70	140.45		203.37	-	22.15	2,611.78	294.38	-
Unit Starts	6	[illegible]	3	[illegible]	5	1	7	0	3	[illegible]	3	0	5	0	4	10	5	0
Hrs/Unit Start	28.09	255.92	52.39	-	16.58	418.00	28.44	-	16.77	131.70	46.82	-	40.67	-	5.54	261.18	58.88	-
% OTAG Outage/Total Outage Hours	29.67%	100.00%	60.08%	0.00%	29.39%	100.00%	53.20%	0.00%	20.71%	100.00%	36.60%	0.00%	34.57%	0.00%	10.93%	78.36%	58.45%	0.00%

2003 Forced Outage Hours

Outage Hours - 2003

2003 Outages	Coleman Unit 1 FO(1)	Date	Type	PO(2)	Coleman Unit 2 FO(1)	Date	Type	PO(2)	Coleman Unit 3 FO(1)	Date	Type	PO(2)
1	60.62	1/21	UO4	---	22.63	1/15	UO1	---	55.92	1/10	UO4	---
2	45.62	3/14	UO1	---	41.50	1/17	UO1	---	1.73	1/13	UO1	---
3	---	3/14	PO	45.62	10.23	1/26	UO4	---	62.55	1/21	UO1	---
4	63.10	5/27	UO4	---	22.37	2/14	UO4	---	19.65	2/8	UO1	---
5	6.30	6/8	UO1	---	31.80	2/15	UO1	---	---	2/15	PO	1,194.08
6	54.00	7/5	UO4	---	20.22	2/17	UO1	---	0.55	4/6	UO1	---
7	61.17	7/12	UO3	---	20.22	2/19	UO1	---	3.80	4/6	UO2	---
8	54.80	7/21	UO4	---	0.77	2/21	UO1	---	2.77	4/8	UO1	---
9	54.98	7/29	UO4	---	22.97	3/16	UO1	---	15.13	4/11	UO4	---
10	70.07	9/3	UO4	---	80.23	4/8	UO1	---	6.37	4/12	UO1	---
11	24.55	12/4	UO1	---	11.77	5/12	UO1	---	9.70	4/13	UO4	---
12	47.07	12/6	UO1	---	---	5/16	PO	445.23	2.13	4/15	UO1	---
13	---	---	---	---	28.87	6/27	UO4	---	1.75	4/25	UO1	---
14	---	---	---	---	7.25	7/12	UO1	---	59.55	5/5	UO1	---
15	---	---	---	---	52.98	6/19	UO4	---	1.03	5/7	UO2	---
16	---	---	---	---	21.75	9/26	UO4	---	16.95	5/25	UO4	---
17	---	---	---	---	28.43	11/20	UO4	---	21.83	8/8	UO4	---
18	---	---	---	---	14.92	12/4	UO1	---	2.15	8/9	UO1	---
19	---	---	---	---	---	---	---	---	30.32	9/27	UO4	---
20	---	---	---	---	---	---	---	---	21.78	10/18	UO4	---
21	---	---	---	---	---	---	---	---	29.17	10/24	UO1	---
22	---	---	---	---	---	---	---	---	38.77	11/22	UO4	---
23	---	---	---	---	---	---	---	---	---	---	---	---
24	---	---	---	---	---	---	---	---	---	---	---	---
Total	542.27			45.62	438.90			445.23	403.60			1,194.08

2003 Outages	Green Unit 1 FO(1)	Date	Type	PO(2)	Green Unit 2 FO(1)	Date	Type	PO(2)	HMPL Unit 1 FO(1)	Date	Type	PO(2)
1	14.12	2/9	UO3	---	49.38	3/14	UO4	---	50.17	1/8	UO2	---
2	1.40	4/20	UO1	---	47.28	5/23	UO4	---	4.13	1/25	UO1	---
3	49.23	4/29	UO2	---	5.20	6/22	UO1	---	53.95	1/31	UO2	---
4	53.63	5/8	UO3	---	3.80	7/9	UO1	---	66.67	2/23	UO2	---
5	15.37	5/28	UO1	---	1.47	8/1	UO1	---	41.18	2/28	UO2	---
6	13.17	5/29	UO1	---	27.88	9/15	UO2	---	59.97	3/17	UO2	---
7	7.95	7/6	UO4	---	---	10/17	BPO	474.58	14.50	3/20	UO2	---
8	7.00	7/16	UO2	---	---	---	---	---	3.13	3/21	BPO/SF	1,422.00
9	2.60	8/7	UO1	---	---	---	---	---	---	5/20	EPO	87.42
10	0.98	8/7	UO1	---	---	---	---	---	---	5/24	EPO	167.38
11	26.15	8/31	UO4	---	---	---	---	---	---	5/31	EPO	16.80
12	4.92	10/27	UO1	---	---	---	---	---	---	5/31	EPO	51.07
13	---	11/7	BPO	410.98	---	---	---	---	---	6/3	EPO	24.05
14	---	11/24	BPO	48.25	---	---	---	---	26.73	7/22	UO2	---
15	---	---	---	---	---	---	---	---	13.42	8/1	UO4	---
16	---	---	---	---	---	---	---	---	8.42	8/18	UO1	---
17	---	---	---	---	---	---	---	---	47.32	8/23	UO4	---
18	---	---	---	---	---	---	---	---	12.18	9/11	UO1	---
19	---	---	---	---	---	---	---	---	3.38	9/21	UO1	---
20	---	---	---	---	---	---	---	---	51.38	10/30	UO4	---
21	---	---	---	---	---	---	---	---	5.53	11/6	UO1	---
22	---	---	---	---	---	---	---	---	47.58	11/14	UO1	---
23	---	---	---	---	---	---	---	---	37.98	12/5	UO4	---
24	---	---	---	---	---	---	---	---	7.43	12/8	UO2	---
Total	196.52			459.23	135.02			474.58	555.07			1,769.72

2003 Outages	HMPL Unit 2 FO(1)	Date	Type	PO(2)	Reid FO(1)	Date	Type	PO(2)	Wilson FO(1)	Date	Type	PO(2)
1	5.23	1/2	UO1	---	3.57	1/18	UO1	---	1,072.67	12/21	UO1	---
2	8.43	1/9	UO1	---	25.12	2/14	UO4	---	4.53	2/14	UO1	---
3	151.83	1/20	UO1	---	51.00	2/21	UO2	---	11.77	2/18	UO1	---
4	3.60	3/7	UO1	---	18.52	3/25	UO1	---	1.82	2/27	UO1	---
5	64.00	3/7	UO4	---	527.23	4/18	UO2	---	2.97	2/27	UO1	---
6	54.07	3/18	UO2	---	3.27	4/18	UO1	---	9.70	3/7	UO1	---
7	125.77	4/7	UO2	---	1.93	5/10	UO1	---	3.33	3/31	UO1	---
8	4.20	4/12	UO2	---	---	6/6	RS	79.92	12.17	5/1	UO1	---
9	2.93	4/25	BPO/SF	493.48	2.37	6/9	UO1	---	9.88	5/10	UO1	---
10	79.45	5/15	UO2/UO4	---	13.15	6/16	UO1	---	35.08	6/1	UO4	---
11	33.18	6/5	UO2/RS	15.83	55.35	6/19	UO4	---	2.85	7/6	UO1	---
12	36.17	8/10	UO2	---	6.55	6/26	UO1	---	2.90	7/23	UO1	---
13	63.28	8/29	UO1	---	50.78	6/27	UO4	---	3.35	8/27	UO1	---
14	2.03	9/24	UO1	---	61.50	8/29	UO2	---	4.53	9/10	UO1	---
15	16.30	11/2	UO1		33.52	9/7	UO2	---	25.50	10/14	UO1	---
16	---	---	---	---	---	9/20	RS	54.58	6.40	10/16	UO1	---
17	---	---	---	---	1.70	9/24	UO1	---	16.45	11/2	UO1	---
18	---	---	---	---	---	10/4	RS	59.55	---	11/28	PO	160.83
19	---	---	---	---	7.97	10/6	UO2	---	---	---	---	---
20	---	---	---	---	4.33	10/14	UO1	---	---	---	---	---
21	---	---	---	---	71.02	12/15	UO4	---	---	---	---	---
22	---	---	---	---	---	12/23	RS	299.22	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
24	---	---	---	---	---	---	---	---	---	---	---	---
Total	651.48			509.32	938.87			493.27	1,226.00			160.83

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).

(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

	Coleman Unit 1 FO(1)	PO(2)	Coleman Unit 2 FO(1)	PO(2)	Coleman Unit 3 FO(1)	PO(2)
OTAG Season Outage Hours:	63.10	—	11.77	—	59.55	—
	6.30	—	—	445.23	1.03	—
	54.00	—	28.87	—	16.95	—
	61.17	—	7.25	—	21.83	—
	54.80	—	52.98	—	2.15	—
	54.98	—	21.75	—	30.32	—
	70.07	—				
TOTAL	364.42	-	122.62	445.23	131.83	-
Unit Starts	7	0	5	1	6	0
Hrs/Unit Start	52.05	-	24.52	445.23	21.97	-
% OTAG Outage/Total Outage Hours	67.20%	0.00%	27.94%	100.00%	32.66%	0.00%

	Green Unit 1 FO(1)	PO(2)	Green Unit 2 FO(1)	PO(2)	HMPL Unit 1 FO(1)	PO(2)
OTAG Season Outage Hours:	17.07	—	47.28	—	3.13	461.35
	53.63	—	5.20	—	—	87.42
	15.37	—	3.80	—	—	167.38
	13.17	—	1.47	—	—	16.80
	7.95	—	27.88	—	—	51.07
	7.00	—			—	24.05
	2.60	—			26.73	—
	0.98	—			13.42	—
	26.15	—			8.42	—
					47.32	—
					12.18	—
					9.38	—
TOTAL	143.92	-	85.63	-	114.58	808.07
Unit Starts	9	0	5	0	6	6
Hrs/Unit Start	15.99	-	17.13	-	19.10	134.68
% OTAG Outage/Total Outage Hours	73.23%	0.00%	63.42%	0.00%	20.64%	45.69%

	HMPL Unit 2 FO(1)	PO(2)	Reid FO(1)	PO(2)	Wilson FO(1)	PO(2)
OTAG Season Outage Hours:	2.93	370.37	1.93	—	12.17	—
	79.45	—	—	79.92	9.88	—
	33.18	15.83	2.37	—	35.08	—
	36.17	—	13.15	—	2.85	—
	63.28	—	55.35	—	2.90	—
	2.03	—	6.55	—	3.35	—
			50.78	—	4.53	—
			61.50	—		
			33.52	—		
			—	54.58		
			1.70	—		
TOTAL	217.05	386.20	226.85	134.50	70.87	-
Unit Starts	5	1	9	2	7	0
Hrs/Unit Start	43.41	386.20	25.21	67.25	10.12	-
% OTAG Outage/Total Outage Hours	33.32%	75.83%	24.16%	27.27%	5.78%	0.00%

2002 Forced Outage Hours

Outage Hours - 2002

2002	Coleman Unit 1				Coleman Unit 2				Coleman Unit 3			
Outages	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	28.57	1/26	UO3	---	27.00	1/12	UO4	---	17.88	2/16	UO1	---
2	1.20	2/27	UO1	---	---	1/28	PO	176.43	2.47	3/6	UO1	---
3	29.43	2/27	UO2	---	47.20	2/28	UO2	---	7.43	3/15	PO /SF	258.13
4	---	3/30	PO	515.25	5.02	4/9	UO1	---	13.98	3/29	UO1	---
5	6.90	4/23	UO1	---	28.98	5/31	UO4	---	33.25	6/8	UO4	---
6	2.87	4/23	UO1	---	1.18	9/11	UO1	---	12.87	6/27	UO1	---
7	30.90	5/6	UO4	---	14.48	10/29	UO1	---	14.50	6/28	UO4	---
8	3.90	5/28	UO1	---	13.73	11/2	UO1	---	18.62	8/16	UO4	---
9	1.42	5/28	UO1	---	14.42	11/7	UO4	---	69.70	8/17	UO1	---
10	18.75	6/9	UO1	---	14.78	11/8	UO4	---	46.25	8/12	UO1	---
11	5.15	7/19	UO1	---	13.65	12/24	UO4	---	55.93	8/27	UO1	---
12	71.57	7/20	UO4	---	---	---	---	---	47.77	10/16	UO1	---
13	88.33	8/24	UO1	---	---	---	---	---	44.27	11/3	UO1	---
14	29.08	10/4	UO4	---	---	---	---	---	5.52	11/5	UO1	---
15	42.58	10/25	UO4	---	---	---	---	---	119.33	11/9	UO1	---
16	53.82	11/14	UO1	---	---	---	---	---	20.00	11/16	UO4	---
17	---	---	---	---	---	---	---	---	49.05	12/16	UO1	---
18	---	---	---	---	---	---	---	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
24	---	---	---	---	---	---	---	---	---	---	---	---
25	---	---	---	---	---	---	---	---	---	---	---	---
Total	414.47			515.25	180.45			176.43	578.62			258.13

2002	Green Unit 1				Green Unit 2				HMPL Unit 1			
Outages	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	0.93	1/14	UO1	---	36.35	3/10	UO4	---	81.82	1/26	UO4 /SF	---
2	8.32	3/10	UO1	---	2.65	4/12	UO1	---	36.07	2/22	UO4 /SF	---
3	1.08	3/11	UO1	---	---	5/10	BPO	312.42	45.15	3/22	UO3 /SF	---
4	23.35	4/13	UO3	---	4.62	8/18	UO1	---	4.83	4/21	UO1	---
5	4.93	4/30	UO1	---	8.00	9/15	UO1	---	---	4/26	BPO	190.13
6	1.73	5/24	UO1	---	---	9/27	BPO	72.02	91.18	9/4	UO3 /SF	---
7	46.68	6/2	UO2	---	43.28	11/9	UO3	---	58.53	9/8	UO1	---
8	6.00	6/19	UO1	---	---	---	---	---	5.97	10/15	UO1	---
9	2.23	6/26	UO1	---	---	---	---	---	38.60	10/28	UO2	---
10	22.12	7/2	UO2	---	---	---	---	---	39.53	10/31	UO2	---
11	21.98	7/21	UO2	---	---	---	---	---	4.13	11/9	UO1	---
12	85.22	9/5	UO1	---	---	---	---	---	137.15	12/5	UO3 /SF	---
13	25.35	9/10	UO2	---	---	---	---	---	52.43	12/15	UO2	---
14	22.37	9/11	UO1	---	---	---	---	---	---	---	---	---
15	25.18	11/18	UO3	---	---	---	---	---	---	---	---	---
16	---	12/6	BPO	200.38	---	---	---	---	---	---	---	---
17	---	---	---	---	---	---	---	---	---	---	---	---
18	---	---	---	---	---	---	---	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
24	---	---	---	---	---	---	---	---	---	---	---	---
25	---	---	---	---	---	---	---	---	---	---	---	---
Total	297.48			200.38	94.90			384.43	595.40			190.13

2002	HMPL Unit 2				Reid				Wilson			
Outages	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	154.28	1/18	UO4	---	---	12/27	RS	51.90	57.92	1/8	UO4 /UO1	---
2	14.85	2/8	UO4	---	10.20	1/16	UO1	---	1.62	1/25	UO1	---
3	70.17	2/16	UO3 /UO4	---	27.58	2/4	UO3 /SF	---	20.53	1/25	UO1	---
4	46.50	3/12	UO2	---	49.45	3/27	UO3	---	2.82	1/28	UO1	---
5	49.15	4/17	UO2	---	33.80	4/2	UO2	---	36.55	3/8	UO3	---
6	10.25	4/21	UO2	---	81.68	5/26	UO1	---		3/26	PO	97.77
7	---	4/26	BPO	218.87	173.07	7/5	UO3	---	5.48	4/14	UO1	---
8	69.87	7/5	UO2	---	47.55	7/29	UO2	---	8.00	4/24	UO1	---
9	69.57	7/13	UO2	---	13.98	8/2	UO3	---	2.95	5/12	UO1	---
10	126.90	8/27	UO2	---	31.25	9/13	UO4	---	58.43	5/24	UO4	---
11	77.55	9/17	UO3	---	6.83	10/2	UO1	---	55.32	7/8	UO1	---
12	2.57	9/27	UO1	---	2.07	10/2	UO1	---	8.37	7/11	UO1	---
13	101.00	10/12	UO2	---	47.57	10/2	UO1	---	62.70	7/12	UO1	---
14	113.25	11/11	UO3	---	8.73	10/15	UO1	---	16.85	10/2	UO1	---
15	---	---	---	---	80.72	11/22	UO4	---	2.70	10/6	UO1	---
16	---	---	---	---	46.88	12/16	UO2	---	---	10/11	PO/ EPO	873.85
17	---	---	---	---	11.75	12/19	UO1	---	---	11/17	EPO	4.00
18	---	---	---	---	11.45	12/23	UO1	---	---	11/17	EPO	0.67
19	---	---	---	---	---	---	---	---	---	11/17	EPO	0.58
20	---	---	---	---	---	---	---	---	---	11/17	EPO	1.37
21	---	---	---	---	---	---	---	---	7.00	11/20	UO1 /PO	6.22
22	---	---	---	---	---	---	---	---	2.27	11/29	UO1	---
23	---	---	---	---	---	---	---	---	3.13	12/3	UO1	---
24	---	---	---	---	---	---	---	---	1.35	12/3	UO1	---
25	---	---	---	---	---	---	---	---	244.98	12/21	UO1	---
Total	904.90			218.87	684.57			51.90	558.97			984.45

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).
(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

OTAG Season Forced Outage Hours:

	Coleman Unit 1 FO(1)	Coleman Unit 1 PO(2)	Coleman Unit 2 FO(1)	Coleman Unit 2 PO(2)	Coleman Unit 3 FO(1)	Coleman Unit 3 PO(2)	Green Unit 1 FO(1)	Green Unit 1 PO(2)	Green Unit 2 FO(1)	Green Unit 2 PO(2)	HMPL Unit 1 FO(1)	HMPL Unit 1 PO(2)	HMPL Unit 2 FO(1)	HMPL Unit 2 PO(2)	Reid FO(1)	Reid PO(2)	Wilson FO(1)	Wilson PO(2)
	30.90	---	28.98	---	33.25	---	1.73	---	---	312.42	---	91.03	---	122.43	81.68	---	2.95	---
	3.90	---	1.18	---	12.87	---	46.68	---	4.62	---	91.18	---	69.87	---	173.07	---	58.43	---
	1.42	---			14.50	---	6.00	---	8.00	---	58.53	---	69.57	---	47.55	---	55.32	---
	18.75	---			18.62	---	2.23	---	---	72.02			126.90	---	13.98	---	8.37	---
	5.15	---			69.70	---	22.12	---					77.55	---	31.25	---	62.70	---
	71.57	---			46.25	---	21.98	---					2.57	---				
	88.33	---			55.93	---	85.22	---										
							25.35	---										
							22.37	---										
TOTAL	220.02	-	30.17	-	251.12	-	233.68	-	12.62	384.43	149.72	91.03	345.45	122.43	347.53	-	187.77	-
Unit Starts	7	0	2	0	7	0	9	0	2	2	2	1	5	1	5	0	5	0
Hrs/Unit Start	31.43	-	15.08	-	35.87	-	25.96	-	6.31	192.22	74.86	91.03	69.09	122.43	69.51	-	37.55	-
% OTAG Outage/Total Outage Hours	53.08%	0.00%	16.72%	0.00%	49.38%	0.00%	78.55%	0.00%	13.29%	100.00%	25.15%	47.88%	38.18%	55.94%	50.77%	0.00%	31.35%	0.00%

2001 Forced Outage Hours

Outage Hours - 2001

2001 Outages	Coleman Unit 1				Coleman Unit 2				Coleman Unit 3			
	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	---	3/5	PO	89.50	38.13	3/17	UO4	---	3.55	1/8	UO1	---
2	21.73	3/18	UO4	---	36.78	4/21	UO4	---	141.90	1/17	UO4	---
3	33.18	5/19	UO4	---	35.07	6/29	UO4	---	7.73	2/21	UO4	---
4	15.97	7/28	UO4	---	30.43	8/20	UO1	---	---	3/21	PO	258.32
5	17.15	8/3	UO4	---	---	10/12	BPO	382.70	1.88	4/1	UO1	---
6	86.83	9/27	UO4 /RS	3.87	24.03	11/9	UO4	---	0.45	4/1	UO1	---
7	---	---	---	---	1.48	11/14	UO1	---	30.67	4/6	UO1	---
8	---	---	---	---	4.47	11/16	UO1	---	17.00	4/11	UO1	---
9	---	---	---	---	4.15	12/24	UO1	---	1.53	4/16	UO1	---
10	---	---	---	---	---	---	---	---	8.93	5/1	UO1	---
11	---	---	---	---	---	---	---	---	25.83	5/31	UO3	---
12	---	---	---	---	---	---	---	---	147.70	7/1	UO4	---
13	---	---	---	---	---	---	---	---	14.37	11/11	UO1	---
14	---	---	---	---	---	---	---	---	0.93	12/29	UO1	---
15	---	---	---	---	---	---	---	---	---	---	---	---
16	---	---	---	---	---	---	---	---	---	---	---	---
17	---	---	---	---	---	---	---	---	---	---	---	---
18	---	---	---	---	---	---	---	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	174.87			93.37	174.55			382.70	402.48			258.32

2001 Outages	Green Unit 1				Green Unit 2				HMPL Unit 1			
	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	7.65	1/1	UO1	---	---	11/6	PO/ EPO	17.83	17.57	2/13	UO4	---
2	---	2/24	BPO	175.37	---	1/2	EPO	14.60	8.17	2/22	UO3	---
3	---	3/3	BPO	3.18	---	1/3	EPO	94.05	---	3/3	BPO	512.87
4	21.62	3/19	UO3	---	---	1/8	EPO	1.18	6.92	3/29	UO1	---
5	0.97	3/31	UO1	---	1.48	2/25	UO1	---	104.92	5/9	UO2	---
6	28.25	6/13	UO2	---		3/30	PO/ EPO	743.53	3.80	8/12	UO1	---
7	47.68	8/6	UO2	---	2.87	5/2	UO1	---	72.15	9/14	UO4	---
8	6.83	10/1	UO2	---	0.48	5/2	UO1	---	7.13	10/3	UO3	---
9	---	10/26	PO/ XPO	764.30	1.72	5/2	UO1	---	57.77	11/16	UO4	---
10	4.12	12/4	UO1	---	0.37	5/3	UO1	---	5.17	11/30	UO1	---
11	4.67	12/6	UO2	---	3.40	5/25	UO1	---	17.87	12/15	UO1	---
12	0.58	12/7	UO1	---	10.75	5/25	UO4	---	52.92	12/17	UO1	---
13	1.70	12/11	UO1	---	4.07	6/2	UO4	---	1.33	12/20	UO1	---
14	1.65	12/20	UO1	---	1.93	6/13	UO1	---	---	---	---	---
15	1.98	12/21	UO1	---	0.68	6/15	UO1	---	---	---	---	---
16	---	---	---	---	46.60	7/13	UO4	---	---	---	---	---
17	---	---	---	---	1.97	7/21	UO1	---	---	---	---	---
18	---	---	---	---	52.80	10/19	UO4	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	127.70			942.85	129.12			871.30	355.70			512.87

2001 Outages	HMPL Unit 2				Reid				Wilson			
	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	6.55	1/28	UO2	---	---	10/28	PO/ EPO	131.25	3.57	3/5	UO1	---
2	2.42	2/8	UO3	---	---	1/5	EPO	1.02	9.38	4/25	UO1	---
3	77.05	2/10	UO2	---	0.38	1/6	UO1	---	9.38	4/26	UO1	---
4	2.35	2/13	UO1	---	112.10	1/26	UO4	---	---	4/28	PO	181.37
5	---	3/9	BPO	204.58	9.68	2/2	UO1	---	105.15	5/18	UO4	---
6	99.23	4/2	UO2 /SF	---	52.45	2/23	UO4 /RS	27.47	54.03	8/18	UO4	---
7	73.17	4/17	UO2	---	232.53	2/26	UO2	---	2.83	9/24	UO1	---
8	53.87	6/20	UO4	---	92.52	5/9	UO3	---	2.05	10/24	UO1	---
9	60.92	8/24	UO4	---	4.93	5/12	UO1	---	2.83	10/28	UO1	---
10	189.03	8/24	SF	---	5.72	5/13	UO1	---	17.28	11/8	UO1	---
11	64.75	9/25	UO4	---	2.08	6/16	UO1	---	4.98	11/24	UO1	---
12	3.08	10/7	UO1	---	69.37	6/24	UO2	---	---	---	---	---
13	36.40	10/12	UO4	---	12.78	6/27	UO3	---	---	---	---	---
14	102.68	10/29	UO2	---	50.97	8/11	UO2	---	---	---	---	---
15	14.02	11/30	UO1	---	70.82	8/30	UO1	---	---	---	---	---
16	17.08	12/18	UO1	---	---	10/2	RS	127.13	---	---	---	---
17	---	---	---	---	1.13	11/22	UO1	---	---	---	---	---
18	---	---	---	---	---	11/22	RS	726.90	---	---	---	---
19	---	---	---	---	---	12/27	RS	117.08	---	---	---	---
20	---	---	---	---	---	---	---	---	---	---	---	---
21	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---
Total	802.60			204.58	717.47			1,130.85	211.50			181.37

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).
(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

	Coleman Unit 1		Coleman Unit 2		Coleman Unit 3		Green Unit 1		Green Unit 2		HMPL Unit 1		HMPL Unit 2		Reid		Wilson	
OTAG Season Outage Hours:	33.18 15.97 17.15 80.37	3.87	35.07 30.43		8.93 25.83 147.70		28.25 47.68		2.87 0.48 1.72 0.37 3.40 10.75 4.07 1.93 0.68 46.60 1.97	21.93	104.82 3.80 72.15		53.87 60.92 189.03 64.75		92.52 4.93 5.72 2.08 69.37 12.78 50.97 70.82		105.15 54.03 2.83	132.43
TOTAL	146.57	3.87	65.50		182.47		75.93		74.83	21.93	180.87		368.57		309.18		162.02	132.43
Unit Starts	3	0	2	0	3	0	2	0	11	1	3	0	4	0	8	0	3	1
Hrs/Unit Start	48.89	-	32.75	-	60.82	-	37.97	-	6.80	21.93	60.29	-	92.14	-	38.65	-	54.01	132.43
% OTAG Outage/Total Outage Hours	83.87%	4.14%	37.53%	0.00%	45.34%	0.00%	59.46%	0.00%	57.96%	2.52%	50.85%	0.00%	45.92%	0.00%	43.09%	0.00%	76.60%	73.02%

2000 Forced Outage Hours

Outage Hours - 2000

2000 Outages	Coleman Unit 1				Coleman Unit 2				Coleman Unit 3				Green Unit 1				Green Unit 2				HMPL Unit 1				HMPL Unit 2				Reid				Wilson			
	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)	FO(1)	Date	Type	PO(2)
1	54.17	1/14	UO4	---	100.23	4/12	UO2	---	2.67	5/22	UO1	---		3/5	BPO	148.97	3.22	1/19	UO1	---	43.42	2/6	UO1	---	173.18	1/1	UO1	---	4.98	12/7	RS /SF	95.67	2.28	1/3	UO1	---
2	160.77	4/28	UO4	---	68.50	6/10	UO3	---	30.42	8/18	UO4	---	61.27	5/8	UO2	---	67.55	2/5	UO3 /SF	---	42.82	2/6	UO3/ PO /SF	175.77	71.50	2/11	UO2	---	9.58	1/11	RS /SF	104.23	4.35	1/3	UO1	---
3	22.70	12/24	UO4	---	68.98	6/21	UO2	---	63.63	11/24	UO2	---	2.70	6/10	UO1	---		2/15	BPO	215.50	12.83	5/15	UO1	---		2/25	BPO	205.18	7.27	2/1	UO1	---	4.03	1/30	UO1	---
4	---	---	---	---	40.87	9/5	UO4 /SF /RS	9.60	97.28	12/23	UO2	---	24.57	7/14	UO2	---	94.28	3/15	UO2	---	14.95	5/27	UO4	---	1.67	3/25	UO1	---	63.45	3/11	UO1	---	73.25	3/21	UO3	---
5	---	---	---	---	38.17	11/13	UO1	---	41.50	12/27	UO2	---	39.93	8/20	UO2	---	46.93	7/15	UO2	---	71.15	6/11	UO3/ PO /SF	---	58.12	6/20	UO2	---	---	4/10	RS /SF	567.87		4/4	PO	540.00
6	---	---	---	---	190.05	11/21	UO1	---	---	---	---	---	7.65	9/11	UO1	---	59.28	7/19	UO2	---	46.40	7/15	UO4	---	3.25	9/11	UO1	---	2.10	5/4	UO1	---	104.03	5/3	UO1	---
7	---	---	---	---	7.85	11/29	UO1	---	---	---	---	---	44.50	9/26	UO4	---	36.45	7/25	UO2	---	5.28	7/18	UO2	---		10/10	PO/ EPO	624.32	---	5/15	RS /SF	170.88	1.72	5/15	UO1	---
8	---	---	---	---	9.30	12/14	UO3	---	---	---	---	---	49.95	10/6	UO2	---	6.37	9/11	UO1	---	7.18	8/6	UO1	---	---	---	---	---	---	6/3	RS /SF	148.08	6.37	10/13	UO1	---
9	---	---	---	---	---	---	---	---	---	---	---	---	22.22	10/14	UO2	---	3.13	11/2	UO1	---	6.08	9/11	UO1	---	---	---	---	---	2.35	6/20	UO1	---	7.72	10/15	UO1	---
10	---	---	---	---	---	---	---	---	---	---	---	---	16.45	10/15	UO2	---		11/6	PO/ EPO	1,324.70	9.83	10/24	UO3/ PO /SF	---	---	---	---	---	3.50	6/27	RS /SF	110.17	5.30	10/16	UO1	---
11	---	---	---	---	---	---	---	---	---	---	---	---	26.70	10/25	UO2	---	---	---	---	---	2.93	11/5	UO1	---	---	---	---	---	1.32	7/24	RS /SF	198.62	3.15	11/29	UO1	---
12	---	---	---	---	---	---	---	---	---	---	---	---	18.80	11/4	UO2	---	---	---	---	---	6.88	11/28	UO1	---	---	---	---	---	41.97	9/3	UO3 /RS	71.38	2.20	11/30	UO1	---
13	---	---	---	---	---	---	---	---	---	---	---	---	14.87	12/11	UO1	---	---	---	---	---	58.98	12/9	UO4 /SF	---	---	---	---	---	1.58	9/21	UO1	---	2.88	12/17	UO1	---
14	---	---	---	---	---	---	---	---	---	---	---	---	64.83	12/28	UO2	---	---	---	---	---	---	---	---	---	---	---	---	---	35.63	10/6	UO3 /RS	---	3.50	12/21	UO1	---
15	---	---	---	---	---	---	---	---	---	---	---	---	2.88	12/31	UO1	---	---	---	---	---	---	---	---	---	---	---	---	---		10/28	BP/ EPO	1,559.18	3.83	12/31	UO1	---
16	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
17	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
18	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
19	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
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21	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
22	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
23	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Total	237.63			-	523.95			9.60	235.50			-	399.32			148.97	317.22			1,540.20	328.75			175.77	307.72			829.50	173.73			3,026.08	224.62			540.00

(1) Forced Outages include items coded as UO1 (immediate), UO2 (delayed), UO3 (postponed), UO4 (deferred) and SF (startup failure).
(2) Planned Outages include items coded as BPO (basic planned outage), PO (planned outage), XPO/EPO (extended planned outage), and RS (reserve shutdowns).

OTAG Season Forced Outage Hours:

	103.20				68.50				2.67				61.27				46.93				12.83				58.12							86.47	104.03			
					68.98				30.42				2.70				59.28				14.95				3.25				2.10				1.72			
					40.87			9.60					24.57				36.45				71.15											170.88				
													39.93				6.37				46.40											148.08				
													7.65								5.28								2.35							
													44.50								7.18								3.50			110.17				
																					6.08								1.32			198.62				
																													41.97			71.38				
																													1.58							
TOTAL	103.20			-	178.35			9.60	33.08			-	180.62			-	149.03			-	163.88			-	61.37			-	52.82			785.60	105.75			-
Unit Starts	1			0	2			1	2			0	6			0	4			0	7			0	2			0	6			3	2			0
Hrs/Unit Start	103.20			-	89.18			9.60	16.54			-	30.10			-	37.26			-	23.41			-	30.68			-	8.80			261.87	52.88			-
% OTAG Outage/Total Outage Hours	43.43%			0.00%	34.04%			100.00%	14.05%			0.00%	45.23%			0.00%	46.98%			0.00%	49.85%			0.00%	19.94%			0.00%	30.40%			25.96%	47.08%			0.00%

Appendix I

Vendor Quotations

Big Rivers
Electric Corporation

Your Touchstone Energy® Cooperative
The power of human connections

Stanley Consultants INC

Green Station Units 1 & 2

Selective Catalytic Reduction of NO_x

ALSTOM Proposal No. 131.0604, Rev. 0
May 26, 2006

Indicative Proposal

ALSTOM

Table of Contents

1 Introduction

ALSTOM Power Environmental Systems is pleased to provide this indicative proposal for SCR systems for Green Station. In responding to this RFP, we have offered our state-of-the-art Selective Catalytic Reactor technology, employed in more than 35,000 MW of electrical generating capacity over a period of two decades.

Our preliminary design and scope relies on information transmitted by Stanley Consultants on May 19, 2006.

This submittal contains preliminary technical data and budgetary pricing, and is not a firm quote or offer to perform the work; ALSTOM reserves the right to amend its budgetary estimate and submittal based on technical, commercial, and any other considerations its management deems necessary or appropriate.

The project includes:

- The SCR reactor
- Testing
- Catalyst removal facilities
- Interconnecting ductwork
- Training
- Control logics for the plant DCS
- Freight
- Support steel
- Catalyst
- Flow model of SCR system
- Access
- Erection for supplied equipment
- Start-up
- Sonic horn cleaning system for the catalyst
- Anhydrous Ammonia Storage, Vaporization and Injection System

We have designed the system without the use of hoppers; careful design of ductwork can minimize the ash fallout and by eliminating hoppers, we avoid the typical costs associated with ash system modification.

The SCR reactor is designed for either a plate or honeycomb-type catalyst. A separate vendor will supply the catalyst so that Big Rivers Electric will not be limited by the reactor design in future catalyst purchases. The design of the

Green Station reactor consists of three-layers—one of which is a spare layer for future addition of catalyst. The catalyst management plan requires that after filling the spare layer, Big Rivers must replace the catalyst layer by layer in the future. Sending the removed catalyst layer for cleaning rather than disposal minimizes this replacement cost.

Precautions:

The listed normal operating temperature for the Green units, 775 degrees Fahrenheit, is at the high end of the range for conventional catalysts. Further, the maximum temperature of 800 degrees Fahrenheit is also near the high end for conventional catalysts. We suggest that Big Rivers examine operating records to verify these temperatures. While it is possible to successfully design a method accommodating these temperatures, they are more costly than a conventional design. In addition, the specified design maximum temperature means the use of an ASTM A588 grade steel since the strength of carbon steel degrades at 750 degrees Fahrenheit.

The tables in the Request for Proposal containing coal and ash analyses for the Green Units show a single CaO value and no data for arsenic content. Since CaO in moderate concentrations mitigates arsenic poisoning, a low concentration of CaO is not an advantage for the SCR performance. High CaO concentrations can cause catalyst poisoning. In addition, evaluation of fuel CaO and arsenic concentrations as they appear *together in the same sample* is necessary. If corresponding CaO and arsenic concentration data are available in the future, the effects of the CaO and arsenic content of the fuels will be properly considered.

2 ALSTOM SCR Experience

ALSTOM is qualified to serve as Big River Electric's supplier for the Green Station SCR system.

Extensive Experience: ALSTOM has an extensive SCR experience base encompassing over 35,000 MW of utility fossil boiler fired boiler installations. The vast majority of ALSTOM's experience has been with the US utility industry.

Innovative Technology: The SCR technology proposed for use at Green Station was developed in-house and is 100% owned by ALSTOM. Further, the Knoxville office serves as the technical lead center for ALSTOM's global SCR business.

Selective Catalytic Reduction: ALSTOM has recently completed four major SCR teaming projects. These projects encompass more than 16,000 MW of SCR projects, all designed, supplied and commissioned from the Knoxville office. This effort has allowed ALSTOM to further refine its approach to fleet-wide retrofits as well as design concepts that are directly transferable to the Big Rivers Electric project.

Alliance-Based Contract Methods: ALSTOM is a leader in developing and implementing non-traditional contracting methods (e.g. alliances, teaming, etc.). We are currently participating in alliance-based contracts with five customers on 24 projects.

Technology Range: Big River Electric will benefit from ALSTOM's extensive gaseous emission control technology portfolio:

- limestone/gypsum WFGD
- lime DFGD
- sodium-based WFGD
- particulate controls
- NO$_x$ controls.

While the focus of this effort is SCR, our expertise with these other technologies proves helpful in integrating SCRs into Green Station's overall air quality control systems.

Particulate Control Systems: ALSTOM also has far-reaching experience in the design and construction of particulate control systems, recently completing the world's largest utility-scale Wet Electrostatic Precipitator retrofit at Dakota Gasification Corporation in Beulah, North Dakota. ALSTOM's particulate control experience will increase the removal of particulate in existing electrostatic precipitators, and assess the impact and develop solutions to future emission control issues such as mercury, SO_3 mist, and PM 2.5.

Backed by an International Corporation: As a member of the ALSTOM family, Environmental Control Systems incorporates the company's diverse array of products and services supporting Big River Electric's SCR project. Specifically, ALSTOM's boiler, turbine, and construction groups can assist in tasks such as assessing NFPA boiler implosion issues, investigating turbine upgrades to offset SCR system auxiliary power demand, and developing construction plans and costs.

Global Support: ALSTOM Power is a global air pollution control company with local representation in many countries around the world. Our broad scope of product lines means we can deliver exactly what our customers need, regardless of requirement diversity. Over the past 25 years, ALSTOM has supplied air pollution control systems for more than 47,000 MW of power generation worldwide. With a full range of key dedicated professionals, ALSTOM has one of the largest, most experienced staffs in the world for executing air pollution control projects.

3 Process Description

3.1 Selective Catalytic Reduction System Principles

Selective Catalytic Reduction (SCR) is a method of reducing the amount of nitrogen oxides (NO and NO_2—used interchangeably with the term, "*NO_x*") in the flue gas of fossil fuel-fired industrial and electric utility equipment. The SCR system is comprised of various components, with the central component being the reactor that contains the catalyst. This catalyst is typically an active phase of vanadium pentoxide on a carrier of titanium dioxide, formed into elements of a parallel flow configuration; plate or honeycomb shaped substrate is the common shape of catalyst elements. The operating temperature for the catalytic process is normally 570 to 750 degrees Fahrenheit.

The SCR process uses ammonia as a reducing agent to convert the NO_x to nitrogen (N_2) and water vapor at the catalyst surface. The ammonia is introduced into the flue gas duct ahead of the SCR reactor and catalyst—the ammonia in the presence of catalyst causes the NO_x to breakdown into nitrogen and water. One mole of ammonia reacts with one mole of NO_x. A minor portion of ammonia will leave the catalyst unreacted. We refer to this as ammonia slip.

Several side reactions may occur under certain conditions but the oxidation of SO_2 to SO_3 is of most concern. Optimal catalyst design reduces the formation of ammonia bisulfate and ammonia sulfate. The oxidation rate increases as the flue gas temperature increases.

3.2 SCR Catalyst

As previously noted, the catalysts used commercially for SCR processes are of a honeycomb or a plate type. Pellet catalysts have fewer applications due to the high-pressure drop characteristics. Honeycomb and plate catalysts are both applicable for coal-fired units and used extensively in those applications.

Honeycomb catalysts are fully extruded or coated on a ceramic monolith carrier. Plate catalysts are typically made of steel plate coated with catalytic material. The catalytic material used in the SCR technology is titanium oxide mixed with oxides of vanadium and in some cases, tungsten or molybdenum. Among the components in the catalytic material, Vanadium oxide is the most active component, originally used for converting SO_2 to SO_3 in manufacturing sulfuric acid. The major portion of the catalytic material consists of titanium oxide.

The major catalyst manufacturers in the world include Haldor Topsoe, Cormetech, Ceram, KWH, Argillon, and Hitachi. Based on experience with the different catalyst manufacturers, ALSTOM will select and supply the most suitable catalyst for Green Station considering the specific conditions supplied by Stanley Consultants. In most cases, there is more than one catalyst suitable for a specific application and each supplier typically uses a special formulation selected for the application. The catalyst manufacturers supply the catalyst in modules of different sizes. However, for this project, the catalyst modules will be approximately 1500 mm high, 2000 mm wide, and 1000 mm deep. The ALSTOM SCR reactor design accommodates the different weights of modules from the various suppliers so that when replacement is required, Big Rivers Electric will not be limited to a single supplier.

ALSTOM will provide catalyst modules, completely assembled and ready for installation into the reactor chamber. Each catalyst module contains lifting lugs for ease of installation and maintenance—a special lifting device used on all modules is included for attachment to the catalyst modules to lift them from the ground. To avoid flue gas bypass, we place the modules on sealing strips between the support structure and the modules. ALSTOM will install baffle plates on the tops and between the modules to avoid dust deposits and provide additional sealing.

Monitoring the catalyst activity minimizes the catalyst cost over the plant lifetime. As the catalyst ages, the ammonia slip increases to its maximum level while the catalyst activity decreases to a percentage of its original level. Examining catalyst deactivation will prevent premature replacement of a catalyst layer.

Each layer of the catalyst in the reactor includes the installation of a number of test elements to gauge the deactivation of the catalyst. These pieces are periodically removed and tested for their remaining activity in a laboratory.

Annual activity testing is common—there will be sufficient test elements included for the expected operating period of the catalyst.

The framework for the catalyst modules is fabricated from steel. The design and fabrication of this framework will be in accordance with the requirements of the American Institute of Steel Construction (AISC) specification for the design, fabrication and erection of structural steel for buildings. Where applicable, ALSTOM provides proper internal module sealing between the catalyst elements and module frame. To facilitate placement and removal of the individual modules, spacing is supplied along two adjacent sides of the reactor; with flashing installed once the modules are in place.

Each module face includes grating (pedal protection) for ease of internal maintenance and inspection. The grating material is of stainless steel, providing corrosion and erosion resistance.

3.3 Catalyst Handling System

The design of the catalyst handling system accommodates a variety of catalyst modules. By using a rented mobile crane, the catalyst handling system allows for the expedient exchange of any catalyst layer when necessary. Replacement or exchange of the SCR catalyst is an outage activity. Exchange of one layer of the SCR catalyst is accomplished within approximately 120 hours excluding cool down time.

In addition to the fixed catalyst handling equipment listed above, the lifting equipment supplied by ALSTOM includes:

Description	Quantity
Catalyst cart for transport of the modules inside the reactor	1
Catalyst cart for use outside the reactor	1
Low-overhead air powered hoist for transport of the modules into and out of the reactor	1
Special lifting beams for attachment of hoists to the modules	2
Electric or air powered winch to raise the catalyst modules from the ground to the work platform.	1

It is important to note that this equipment is not duplicated for each catalyst elevation and must be moved to each catalyst layer being exchanged. Each of the reactors will be fitted with a complete complement of lifting and moving equipment. The catalyst is supplied in modules. The design of the lifting system is for a common size of modules, approximately 1m x 1.5m in plan area—each module weighs approximately 4000 lb. The modules consist of a steel box filled with catalyst and with top lifting attachment points and are base supported on beams with sealing strips when installed.

The handling procedure for the addition of new catalyst to an empty layer is as follows:

1. The new catalyst modules are delivered to the plant and stored at grade.
2. The transport truck is parked close to the SCR reactor within lift reach of the winch.
3. The special lifting beam is attached to the module.
4. The winch is used to bring the module up from grade to the installation level.
5. At the installation level, the module is placed on the outside cart on the work platform.
6. The winch cable is unhooked.
7. The catalyst on the outside cart is transported to the entrance door to the reactor.
8. The air powered hoist attached to the monorail is used to lift the module a few inches off the cart for transport into the reactor. The hoist also has an air-powered trolley.
9. Inside the reactor, the module is lowered onto the catalyst cart for final transport on the support beams to its final installed position.
10. The lifting beam is used to remove the catalyst module from the cart, position it and it is then removed.
11. Sealing strips are attached to the top of the support beams before the module is lowered onto them. The workers push the cart into position, lower the module onto the strips and pull the cart back to receive the next module. The air-powered hoist can be used to move the cart from track to track. The only manual operations are rolling the carts and swinging the jib crane; all other operations are powered.

3.4 Ammonia/Air Supply

There are three primary types of ammonia supply:

1. Anhydrous ammonia, with almost 100% NH_3
2. Aqueous ammonia; with usually 19–29% NH_3 by weight
3. Urea

This proposal will provide an anhydrous ammonia system for supplying ammonia for use in the SCR.

The anhydrous ammonia system typically consists of truck unloading facilities, storage tank, electric vaporizer, valves, piping, and controls. The amount of ammonia vaporized is regulated by the "demands" of the SCR. The ammonia vapor goes to an ammonia flow control unit adjacent to the SCR reactor where the flow rate is controlled. The ammonia vapor is mixed with dilution air for injection into the SCR inlet flue gas. Separate air blowers supply the dilution air.

3.5 Ammonia Injection/Mixing

The air/ammonia mixture is injected into the flue gas duct. Because of the system layout and design, ALSTOM will supply a large static mixer, which will include ammonia injection. This injection system/mixer will provide the mixing of the ammonia with the flue gas and provide the uniform NO_x and temperature distribution to the catalyst.

3.6 Process Parameters

The NO_x removal reaction depends on several factors. The two most important factors are mentioned below:

3.6.1 Temperature

Generally, the operating temperature for SCR systems with Vanadium/Titanium based catalyst is in the range of 570 to 750 degrees Fahrenheit. The minimum operating temperature depends on SO_3 and ammonia concentration. SCR systems for boilers with high SO_3 concentration and high NO_x reduction requirement need a minimum operating temperature higher than 570 °F. It is expected that the minimum operating temperature for the Green units is about 630 degrees Fahrenheit, because of the potential for ammonium bisulfate deposition. Lower temperatures at reduced loads may require a bypass of the economizer (water or gas) to maintain adequate SCR inlet temperature.

3.6.2 Homogeneity

Uniform gas velocity, temperature and NH_3/NO_x ratio distribution over the catalyst cross section is important in order to achieve high conversion rates. The distribution of NH_3/NO_x ratio is the dominant effect. In cases with high SO_3 concentration, the distribution of flue gas temperature can also be crucial. Such distribution requirements become integral to the overall performance and selection of a catalyst and sometimes necessitate that trade-offs occur between certain performance issues. The model study will determine the gas distribution devices and vane requirements for the proper distribution in the reactor. It is planned that a mixer will be provided which will mix the ammonia and flue gas and provide the mixing required for the proper distribution of ammonia, flue gas, and temperature.

3.7 Process Control

The amount of ammonia fed to the SCR system will be controlled such that the pre-determined NO_X concentration downstream of the SCR system always meets the emission requirements. The most common way of controlling the ammonia injection is to use a set point for the outlet NO_x concentration, thus keeping the NO_x emission at a constant level across the entire load range of the SCR reactor. The objective is to maintain the emission just below the required emission in order to reduce ammonia consumption at lower boiler loads, and the lowest achievable ammonia slip. Alternatively, NO_x removal efficiency can be fixed and the control system will calculate a required outlet NO_x concentration at any operating condition. The operator would select the choice of control method.

The general control principle is as follows: upstream of the SCR system, the NO_x concentration of the flue gas is measured, (the boiler load signal is integrated to provide a faster controlling system required during the rapid load changes). The multiplication of NO_x inlet with flue gas flow, calculated in the distributed control system (DCS) or in the SCR PLC control system by the fuel flow or an equivalent signal, and considering the oxygen content, determines the mass flow of NO_x. The NO_X mass flow signal multiplied with the stoichiometric NH_3/NO_x factor provides a signal (feed forward), which regulates the ammonia control valve flow.

To meet the emission requirements, a correction of the primary signal is achieved by measuring the NO_x concentrations downstream of the SCR system and providing feedback to the control system for further trimming of the control valve.

The basis of the ammonia flow control is the stoichiometric ratio of NH_3 to NO_x.

There is one major interlock for the SCR system. This is the minimum injection temperature. Because of the potential to form ammonium bisulfate below certain flue gas temperatures when there is sufficient ammonia and SO_3 in the flue gas, a minimum ammonia injection temperature is established. The injection of ammonia is interlocked to this minimum temperature and ammonia flow will be stopped when the flue gas temperature drops below this minimum value. Ammonia flow cannot be established until the flue gas temperature exceeds this value during startup.

3.8 SCR Arrangements

The usual location of the SCR system is between the economizer and the air preheater since the flue gas temperature leaving the economizer is typically at the proper level for the SCR process—called a *hot-side SCR system* arrangement. However, it is possible to locate the SCR system downstream of the air heater; a *cold-side SCR system* arrangement. If located downstream of both and ESP and a flue gas desulfurization (FGD) system, the system is referred to as a *tail-end SCR system.*

The SCR system for the Green Station will be a hot side, high dust system and will be located between the economizer and air heater. The system will be equipped with a bypass and will use guillotine dampers for isolation.

3.9 System Startup/Shutdown

To start up and shut down the SCR system, we encourage Big River to follow these general procedures and sequences. Depending upon the overall system design and layout, certain modifications to the procedure may be necessary and, if so, ALSTOM will provided them.

3.9.1 Start Up Procedure

The start up procedure from cold condition of the SCR system, *cold start-up*, includes more steps and is described below.

- Purge the boiler and gas path.
- Start up the ammonia system according to instructions provided. However, do not open the ammonia isolation valves to the SCR system.
- Place firing equipment in service as required for boiler warm-up.
- Place the SCR Sonic Horn cleaning system in automatic operation.
- Open the SCR inlet and outlet dampers, then close the bypass dampers.
- Heat the SCR reactor with flue gas until the temperature in the SCR reactor is above the minimum operating temperature.
- Start the ammonia injection system control loop and open the ammonia shut off valve.

3.9.2 Shut Down Procedure

- Shut off the ammonia supply valve and stop the ammonia injection system control loop.
- Stop the ammonia supply system.
- Open the bypass damper, and then close the SCR inlet and outlet dampers.
- Vent and purge the reactor of flue gases.
- After stopping gas flow in the reactor, the SCR Sonic Horn cleaning system can be shut off.

3.9.3 Lay-up of Reactor

When the SCR will be out of service for an extended time, the reactor should be purged as the boiler is taken out of service. While the reactor is out of service, warm air (approximately 100 degrees Fahrenheit) must be circulated throughout the reactor to keep the catalyst bed from becoming the cold spot and a place for condensation to form.

3.10 Expected Performance Data

Performance Item	Typical Value
NO_x Emission	90 % NOx reduction or 0.041 lb/MBtu emission
Ammonia Slip	2 ppmvd @ ref O_2
$SO_2 - SO_3$ Conversion	<1.5 % initial catalyst charge
Catalyst Life	17,500 operating hours
Pressure Loss	6 in wg in SCR system
Boiler Turndown	~50 % load

4 Scope of Supply

The SCR configuration is a vertical down-flow reactor, using three layers of catalyst. Two layers of catalyst are installed initially and the third layer will be added in the future as required for performance.

All items listed below are for one unit. It is possible to share the urea/ammonia system amongst the four Green units and the design optimized for low cost with maximum flexibility. To avoid confusion, in this tabulation, one system for each unit is displayed.

4.1 SCR System Equipment

Quantity		Item	Description
1	Units	SCR Reactor	SCR Reactors (each 45 ft x 36 ft), fabricated from A588 steel plate, externally stiffened. The reactor is configured to hold three layers of catalyst. Flow turning and straightening vanes are provided to optimize the removal of NO_x and maintain minimum flue gas pressure loss.
1	Units	Sample Grids	One sample grid including tubing to each of 48 locations in the SCR reactor at one level, after the second catalyst layer.
24	Units	Sonic horns	Sonic Horns to clean the catalyst and maintain open gas passages through the SCR catalyst system. Each catalyst layer is equipped with six (6) sonic horns
230	m^3	SCR Catalyst Modules	Initial charge of high dust type catalyst. The catalyst material is furnished installed in a steel framework with a size of 1500 mm high, 2000 mm wide, and 1000 mm deep.
1	Lot	Structural Support Steel	Support steel for the SCR and ductwork.
1	Lot	Access	Access will be provided at each catalyst level, including 2' X 3' quick opening doors for internal inspection and larger doors (welded closure) for catalyst removal and replacement. Platforms

Quantity		Item	Description
			and walkways will be provided connecting to the existing boiler area platforms. Access to the ammonia injection point will also be provided.
1	Lot	Catalyst Handling Equipment	The SCR Reactor is equipped with a complete set of catalyst handling and hoisting equipment, including carts, air powered hoists, electric hoists, and crane beams that provide a permanently installed method of removing and replacing catalyst blocks.
1	Lot	Flue Gas Ductwork	¼" A588 steel ductwork with appropriate stiffening and supports. Ductwork extends from the economizer outlet to the SCR, from the SCR to the air heater. The duct will include sample connections for measuring performance of the SCR system.
1	Lot	Flow Model Study	Physical Scale model of SCR system including report
1	Lot	Economizer Bypass System	Presently not required (low load temperatures appear high enough) and not included, the economizer bypass could be for flue gas or water. A procedure may be used where the operating procedures are revised to the feed water heaters, which increases the economizer outlet gas temperature. The best method of maintaining SCR inlet temperature will be determined in conjunction with Stanley Consultants and Big Rivers Electric.
1	Lot	SCR system bypass duct	This includes duct to connect the economizer outlet with the air heater inlet. Guillotine dampers for closing this connection when the SCR is in service are included. Guillotine dampers will also be provided for SCR isolation.

4.2 Mechanical Equipment

Quantity		Item	Description
1	*Unit*	*Anhydrous Ammonia System*	Anhydrous ammonia system including truck unloading, storage tank with 14 days (operation at full load) capacity, two electric vaporizers, piping and valves
2	Each	Dilution Air Fans	2 x 100% Dilution air fans. One operating, one spare. These fans are for diluting the ammonia vapor before injection into the duct.
1	Lot	Ammonia Piping	Ammonia piping (vapor)/Dilution air duct/mixing element and distribution from the vaporizer to the AFCU into the injection mixer.
1	Units	Static Mixer	This will be a Sulzer (or similar) static mixer for in duct mixing of ammonia and flue gas. This mixer will include an ammonia injection grid. One for each reactor. Each mixer is a two stage mixer

4.3 Electrical/Control Equipment

Quantity		Item	Description
1	Lot	Primary SCR instruments	Primary instrumentation for the operation of the SCR
1	Lot	Logic Diagrams	Logic Diagrams for integration of the SCR system into *the existing plant DCS control system.*
1	Unit	NO_x Analyzer System	An extractive NO_x analyzer system including probes and analyzer for the SCR inlet and separate probes and analyzer for the SCR outlet

4.4 Utility Consumption

ALSTOM expects each SCR system for Green Units 1 & 2 to require the following utilities from the plant:

- Ammonia – 400 lb/hr
- Electric Power—90 kW
- Compressed Air—120 cfm @ 100 psi

5 Indicative Pricing

ALSTOM's indicative pricing to supply and erect SCR systems for Big Rivers Electric Green Units 1 & 2 is $80,000,000 ($40,000,000 each unit).

With regard to the pricing provided above, please note the following:

This submittal contains preliminary technical data and budgetary information, and is not a firm quote or offer to perform the work; ALSTOM Power Inc. reserves the right to amend its budgetary information and submittal based on technical, commercial, and any other considerations its management deems necessary or appropriate.

Pricing is present-day and based on a Notice to Proceed on or before July 1, 2006.

The price assumes that payment terms will be negotiated that provide for a cash-neutral position for ALSTOM at all times.

6 Schedule

A typical schedule for this work would be 22 to 26 months for each unit. The units would probably be staggered by 6 months so outages would not overlap. Thus, an overall duration would be about 28 to 32 months. ALSTOM is currently working on several similar retrofit projects. Our technical expertise and our project execution experience make us confident in our abilities to support Big Rivers' schedule requirements. We are seeing a lengthening of durations for the procurement and fabrication of certain commodities, thus the schedule could get longer depending on market conditions.

Many site-specific factors will govern the project time-line for the Green Station project. Upon award of a project, ALSTOM will develop a detailed plan and schedule that takes into account all critical success factors. Factors include and are not limited to the following:

- existing plant layout
- general arrangements
- soil conditions
- underground utilities
- existing plant systems modifications (e.g. ID/FD fan upgrade or replacement)
- run-in periods required for new or upgraded equipment
- environmental restrictions
- plant operations
- plant outage requirements
- transportation logistics
- critical craft man-power availability

Bermel, Cathy

From: Krekeler, Daniel G [dgkrekeler@babcock.com]
Sent: Tuesday, June 13, 2006 4:32 PM
To: Walters, Ray
Cc: Baltazar, Abraham D; Hansen, Elizabeth A; Koslosky, John V
Subject: P-007298 Green SCR Budget estimate
Attachments: Big Rivers Green Units 1 and 2 _2_.pdf

Dear Mr. Walters;

The Babcock & Wilcox Company is please to provide the following budgetary information for your use regarding the addition of SCR's to WKE (Big Rivers) Green Station. We have looked at this in very general fashion and expect there to be one common project to execute the procurement and installation. Also we have not visited the site to confirm installation difficulty, and therefore hemmed in our estimate between medium to difficult to provide the range. Further review would be required to refine this information.

The budgetary price to perform this project on a D&E basis is estimated to be between $65,000,000.00 (Sixty Five Million Dollars) and $80,000,000.00 (Eighty Million Dollars).

Attached is a document defining the basis of this estimate.

Should you have questions and/or comments on the attached please give me a call.

Thank You.

Daniel G. Krekeler
The Babcock & Wilcox Company
District Sales Engineer
11499 Chester Rd., Ste 701
Cincinnati, Ohio 45246

dgkrekeler@babcock.com
513-326-4364 (phone)
513-326-4360 (fax)
513-379-2038 (cell)

Generating Powerful Solutions^{SM}

Green Units 1 & 2
Selective Catalytic Reduction Systems

Design Parameter (Please verify)	
Generating Capacity	250 MW
Primary Fuel / Start-up Fuel	W Kentucky Bit / oil
Gas Temp (Full Load) @ Econ Outlet	775-800 °F
Gas Flow (Full Load) @ Econ Outlet	2,594,000 lb/hr*
NOx @ Econ Outlet	0.412 lb/mkb
NOx Removal Efficiency	90 %
Outlet NOx Required at Stack	0.041 lb/mkb
Boiler Base Loaded or Cycling Operation	50% turndown (635 °F)
Ammonia type (Urea, Anhydrous, Aqueous)	anhydrous
Ammonia Storage Capacity	2 weeks
Ammonia Slip (average)	2 ppm
Arrangement/Construction Difficulty	Moderate
Contract Award to Operation	24 months

* Specified value – seems somewhat high

Scope of Work

SCR reactor and flues with guillotine dampers (inlet/outlet)
Support steel – average difficulty
SCR catalyst – 17,500 hour life
Catalyst loading system
Sootblowers – rake type with steam and condensate return piping, etc.
SCR bypass with double louver damper
Redundant steam coil air heater systems for seal air and dilution air
Anhydrous ammonia storage, control and injection systems – two 100% tanks for 14 day supply and two 100% feed pumps
Ammonia unloading station
Local controls
Local electrical connections
Engineering services including project management, modeling, start-up/tuning, testing support, and training
Erection

Items Not Included

Foundations
DCS interface
Electrical interface
Boiler modifications
Modifications to ash handling systems
Air heater modifications/relocation/replacement
ID/FD fan modifications/ replacement
Boiler/precipitator implosion studies or stiffening
Hazardous material removal (including asbestos)

Assumptions

B&W has assumed the following for the purpose of preparing this estimate:

- Existing equipment/undergrounds do not constrain options for placement of foundations and routing of support steel.
- Existing equipment over and around the air heaters is not arranged so as to constrain the location of the SCR reactors and associated flue work.
- The ammonia system can be located in reasonable proximity to the SCR inlet fluework.
- Construction equipment can be located and operated such that the SCR system can be erected straightforwardly.
- Two units will be retrofit with scheduled tie-in outages no more than six – twelve months apart.

Bermel, Cathy

From: Walters, Ray
Sent: Thursday, June 22, 2006 8:06 AM
To: rabrams@babcockpower.com
Cc: Bermel, Cathy
Subject: RE: Big Rivers Electric Corporation - Green Units 1 and 2 SCR Budget Quote

Thanks Rich. We will include the costs in our report.

Thanks
Ray Walters
Senior Project Manager
Stanley Consultants, Inc.
9200 E. Mineral Ave. Suite 400
Englewood, CO. 80112
303-925-8284
303-589-9184 (cell)

From: rabrams@babcockpower.com [mailto:rabrams@babcockpower.com]
Sent: Wednesday, June 21, 2006 10:55 PM
To: Walters, Ray
Cc: BBasile@babcockpower.com; GBraveman@babcockpower.com; mpersichilli@babcockpower.com; Schebler, Steven
Subject: RE: Big Rivers Electric Corporation - Green Units 1 and 2 SCR Budget Quote

Ray,

We have reviewed the scope of work and drawings sent by Cathy Bermel as well as the historical information on the Green projects from our files. Sorry for the delay in our response- the files were in our archives off site.

The scope of work is quite similar to the other SCR projects we have completed for LG&E so our data base of information is quite relevant to this project. A review of the drawings to determine whether we could fit the SCR reactor in and erect it shows no apparent major complications.

We estimate that the installed cost for the scope of work defined in your letter of May 19, 2006 would be approximately $139/kw. The only exception to the scope is the ammonia, steam, and condensate piping is not included, since we have not had the opportunity to develop a GA and the piping runs.

Please advise if you need additional information or if we can be of further assistance.

Rich Abrams
Director of Business Development
Babcock Power Environmental Inc.
Worcester, Massachusetts
Phone: 508.854.1140

Appendix J

Present Value Analysis

TABLE J-1
PRESENT VALUE ANALYSIS

Study Parameters (2006)	Option 1	Option 2	Option 3
Probable Project Costs (SCR Costs) (1)	$102,064,000	$53,848,000	$0
Probable Neural Network Costs (2)	$0	$2,223,000	$0
TOTAL PROJECT COST (Owner's Cost)	$102,064,000	$56,071,000	$0
Annual Fixed O&M (3)	$967,000	$489,000	$0

Variable O&M (2006):		Option 1	Option 2	Option 3
Anhydrous Ammonia ($/Ton) (4)	Refer to Notes			
Ammonia Consumption (Tons/MWh) (4)	0.0008			
Emulsified Sulfur ($/year) (5)		$86,000	$43,000	$0
Catalyst Replacement (6)		$5,262,000	$2,659,000	$0
Annual Auxiliary power (kW) (7)		2,722	1,388	0
Auxilary Power Price ($/MWh) (7)	Refer to Notes			
Heat Rate Penalty (Btu/kWh) (8)	61 Green 1 79 Green 2			

Financial Parameters (2006) (9)	
Interest Rate	5.75%
Financing Term (years)	34
Capital Recovery Factor	0.06760
Discount Rate	8.00%
Escalation Rate	3.00%

Year >>>>		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2007-2023
Green Unit 1 MWh (10)		1,850,000	1,859,000	1,823,000	1,860,000	1,855,000	1,671,000	1,881,000	1,864,000	1,822,000	1,847,000	1,849,000	1,685,000	1,852,000	1,861,000	1,814,000	1,853,000	1,859,000	31,085,000
Green Unit 2 MWh (10)		1,830,000	1,679,000	1,813,000	1,800,000	1,756,000	1,787,000	1,790,000	1,654,000	1,786,000	1,798,000	1,741,000	1,771,000	1,793,000	1,832,000	1,800,000	1,798,000	1,748,000	29,974,000
Price of Ammonia ($/Ton) (4)		$406.20	$428.87	$448.21	$470.62	$484.74	$499.28	$514.26	$529.69	$545.58	$561.94	$578.80	$596.17	$614.05	$632.47	$651.45	$670.99	$691.12	
Auxiliary Power Price ($/MWh) (7)		$21.27	$21.57	$23.43	$24.17	$24.90	$25.64	$26.41	$27.20	$28.02	$28.86	$29.73	$30.62	$31.54	$32.48	$33.46	$34.46	$35.49	
Green Fuel Cost ($/mmBtu) (11)		$1.123	$1.147	$1.223	$1.298	$1.342	$1.375	$1.407	$1.440	$1.469	$1.499	$1.530	$1.562	$1.593	$1.625	$1.660	$1.698	$1.732	
Emission Allowance Price ($/Ton) (12)		$2,459	$2,262	$2,642	$2,487	$2,291	$1,944	$1,758	$1,435	$1,121	$1,153	$1,184	$1,217	$1,241	$1,265	$1,274	$1,189	$1,158	
Option 1 - Install SCRs on Green Units 1 & 2																			
Excess NO_X Allowances (13)		0	0	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	1222	18,330
Additional NO_X Allowances Needed (17)		714	706	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,420
Debt Service		$0	$0	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$6,899,785	$103,496,770
Fixed O&M		0	0	1,056,667	1,088,367	1,121,018	1,154,649	1,189,288	1,224,967	1,261,716	1,299,567	1,338,554	1,378,711	1,420,072	1,462,674	1,506,554	1,551,751	1,598,304	19,652,859
Variable O&M: Ammonia		0	0	1,303,753	1,377,975	1,400,313	1,381,210	1,502,048	1,490,751	1,574,755	1,638,631	1,662,323	1,648,283	1,790,577	1,767,385	1,883,467	1,958,759	1,994,300	24,374,531
Emulsified Sulfur		0	0	93,975	96,794	99,698	102,688	105,769	108,942	112,210	115,577	119,044	122,615	126,294	130,083	133,985	138,005	142,145	1,747,824
Catalyst		--	--------	--------	--------	--------	6,283,103	--------	6,665,744	--------	7,071,688	--------	7,502,354	--------	7,959,247	--------	8,443,965	--------	43,926,102
Auxiliary Power		0	0	502,814	518,694	534,255	550,283	566,791	583,795	601,309	619,348	637,928	657,066	676,778	697,082	717,994	739,534	761,720	9,365,391
Heat Rate Penalty		0	0	311,168	331,847	338,022	334,268	358,688	351,693	370,535	381,809	383,002	379,088	405,608	393,980	419,738	432,339	435,582	5,627,565
Sale of Excess NO_X Allowances		0	0	(3,228,524)	(3,039,114)	(2,799,602)	(2,375,568)	(2,145,832)	(1,753,570)	(1,369,862)	(1,408,966)	(1,446,848)	(1,487,174)	(1,516,502)	(1,545,830)	(1,556,826)	(1,452,858)	(1,412,632)	(29,539,810)
Purchase of Additional NO_X Allowances Needed		1,755,726	1,596,972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,352,698
Net Costs		$1,755,726	$1,596,972	$6,939,637	$7,274,348	$7,593,488	$14,330,418	$8,476,537	$15,572,306	$9,450,447	$16,617,439	$9,593,788	$17,100,728	$9,802,612	$17,764,405	$10,004,695	$18,711,180	$10,419,203	$183,003,929
Present Value of Net Costs	$85,822,592	$1,625,672	$1,369,146	$5,508,908	$5,346,863	$5,168,000	$9,030,594	$4,945,978	$8,413,233	$4,727,577	$7,697,089	$4,114,611	$6,790,935	$3,604,400	$6,048,088	$3,153,897	$5,461,615	$2,815,987	$85,822,592
Option 2A - Install SCR on Green Unit 1																			
Excess NO_X Allowances (14)		0	0	457	457	457	457	457	457	457	457	457	457	457	457	457	457	457	6,855
Additional NO_X Allowances Needed (17)		714	706	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,420
Debt Service		$75,140	$150,280	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$57,083,543
Fixed O&M		0	0	534,344	550,374	566,885	583,892	601,408	619,451	638,034	657,175	676,890	697,197	718,113	739,656	761,846	784,701	808,242	9,938,209
Variable O&M: *Ammonia*		0	0	653,669	700,283	719,352	667,439	765,629	789,869	795,234	830,330	856,166	803,634	909,780	941,627	945,382	994,678	1,027,836	12,400,906
Emulsified Sulfur		0	0	46,987	48,397	49,849	51,344	52,885	54,471	56,105	57,788	59,522	61,309	63,147	65,041	66,993	69,002	71,072	873,912
Catalyst		--	--------	--------	--------	--------	3,174,985	--------	3,368,342	--------	3,573,474	--------	3,791,098	--------	4,021,976	--------	4,266,914	--------	22,196,789
Auxiliary Power		0	0	256,394	264,492	272,427	280,600	289,018	297,688	306,619	315,817	325,292	335,051	345,102	355,455	366,119	377,103	388,416	4,775,592
Heat Rate Penalty		0	0	136,001	147,271	151,854	140,155	159,724	163,734	163,268	168,888	172,567	160,550	179,964	184,472	183,686	191,704	196,407	2,500,245
Sale of Excess NO_X Allowances		0	0	(1,207,394)	(1,136,559)	(1,046,987)	(888,408)	(802,492)	(655,795)	(512,297)	(526,921)	(541,088)	(556,169)	(567,137)	(578,105)	(582,218)	(543,373)	(528,292)	(10,673,235)
Purchase of Additional NO_X Allowances Needed		1,755,726	1,596,972	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,352,698
Net Costs		$1,830,866	$1,747,252	$4,210,543	$4,364,799	$4,503,921	$7,800,548	$4,856,713	$8,428,301	$5,237,504	$8,867,093	$5,339,891	$9,083,210	$5,439,511	$9,520,664	$5,532,348	$9,931,271	$5,754,223	$102,448,659
Present Value of Net Costs	$49,176,373	$1,695,246	$1,497,987	$3,342,465	$3,208,258	$3,065,293	$4,915,668	$2,833,845	$4,553,549	$2,620,056	$4,107,180	$2,290,188	$3,607,068	$2,000,097	$3,241,415	$1,744,027	$2,898,843	$1,555,166	$49,176,373
Option 2B - Install SCR on Green Unit 1																			
Excess NO_X Allowances		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional NO_X Allowances Needed (15) (17)		714	706	230	230	230	230	230	230	230	230	230	230	230	230	230	230	230	4,870
Debt Service		$75,140	$150,280	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$3,790,541	$57,083,543
Fixed O&M		0	0	534,344	550,374	566,885	583,892	601,408	619,451	638,034	657,175	676,890	697,197	718,113	739,656	761,846	784,701	808,242	9,938,209
Variable O&M: Ammonia		0	0	653,669	700,283	719,352	667,439	765,629	789,869	795,234	830,330	856,166	803,634	909,780	941,627	945,382	994,678	1,027,836	12,400,906
Emulsified Sulfur		0	0	46,987	48,397	49,849	51,344	52,885	54,471	56,105	57,786	59,522	61,308	63,147	65,041	66,993	69,002	71,072	873,912
Catalyst		--	--------	--------	--------	--------	3,174,985	--------	3,368,342	--------	3,573,474	--------	3,791,098	--------	4,021,976	--------	4,266,914	--------	22,196,789
Auxiliary Power		0	0	256,394	264,492	272,427	280,600	289,018	297,688	306,619	315,817	325,292	335,051	345,102	355,455	366,119	377,103	388,416	4,775,592
Heat Rate Penalty		0	0	136,001	147,271	151,854	140,155	159,724	163,734	163,268	168,888	172,567	160,550	179,964	184,472	183,686	191,704	196,407	2,500,245
Sale of Excess NO_X Allowances		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of Additional NO_X Allowances Needed		1,755,726	1,596,972	607,660	572,010	526,930	447,120	403,880	330,050	257,830	265,190	272,320	279,910	285,430	290,950	293,020	273,470	265,880	8,724,348
Net Costs		$1,830,866	$1,747,252	$6,025,597	$6,073,368	$6,077,838	$9,136,076	$6,063,085	$9,414,146	$6,007,631	$9,659,204	$6,153,299	$9,919,289	$6,292,078	$10,389,719	$6,407,586	$10,748,114	$6,548,395	$118,493,544
Present Value of Net Costs	$57,793,767	$1,695,246	$1,497,987	$4,783,313	$4,464,107	$4,136,475	$5,757,277	$3,537,752	$5,086,170	$3,005,311	$4,474,080	$2,639,044	$3,939,086	$2,313,584	$3,537,295	$2,019,938	$3,137,272	$1,769,828	$57,793,767

TABLE J-1
PRESENT VALUE ANALYSIS

Year >>>>			2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2007-2023
Option 3A - Purchase Additional NO_x Allowances Needed																				
Excess NO_X Allowances			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional NO_X Allowances Needed (18) (17)			714	706	849	849	849	849	849	849	849	849	849	849	849	849	849	849	849	14,155
Debt Service			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fixed O&M			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable O&M:	Ammonia		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Emulsified Sulfur		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Catalyst		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Auxiliary Power		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Heat Rate Penalty		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sale of Excess NO_X Allowances			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of Additional NO_X Allowances Needed			1,755,726	1,596,972	2,243,058	2,111,463	1,945,059	1,650,456	1,490,844	1,218,315	951,729	978,897	1,005,216	1,033,233	1,053,609	1,073,985	1,081,626	1,009,461	981,444	23,181,093
Net Costs			$1,755,726	$1,596,972	$2,243,058	$2,111,463	$1,945,059	$1,650,456	$1,490,844	$1,218,315	$951,729	$978,897	$1,005,216	$1,033,233	$1,053,609	$1,073,985	$1,081,626	$1,009,461	$981,444	$23,181,093
Present Value of Net Costs		$13,644,261	$1,625,672	$1,369,146	$1,780,612	$1,551,988	$1,323,774	$1,040,067	$869,893	$658,218	$476,101	$453,419	$431,120	$410,311	$387,410	$365,650	$340,974	$294,652	$265,254	$13,644,261
Option 3B - Purchase Additional NO_x Allowances Needed																				
Excess NO_X Allowances			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional NO_X Allowances Needed (16) (17)			714	706	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	1703	26,965
Debt Service			$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fixed O&M			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable O&M:	Ammonia		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Emulsified Sulfur		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Catalyst		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Auxiliary Power		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Heat Rate Penalty		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sale of Excess NO_X Allowances			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of Additional NO_X Allowances Needed			1,755,726	1,596,972	4,499,326	4,235,361	3,901,573	3,310,632	2,990,468	2,443,805	1,909,063	1,963,559	2,016,352	2,072,551	2,113,423	2,154,295	2,169,622	2,024,867	1,968,668	43,126,263
Net Costs			$1,755,726	$1,596,972	$4,499,326	$4,285,361	$3,901,573	$3,310,632	$2,990,468	$2,443,805	$1,909,063	$1,963,559	$2,016,352	$2,072,551	$2,113,423	$2,154,295	$2,169,622	$2,024,867	$1,968,668	$43,126,263
Present Value of Net Costs		$24,356,422	$1,625,672	$1,369,146	$3,571,710	$3,113,117	$2,655,345	$2,086,260	$1,744,909	$1,320,312	$955,007	$909,508	$864,779	$823,039	$777,101	$733,454	$683,955	$591,039	$532,070	$24,356,422

NOTES:

(1) Refer to Table 6-5 for a breakdown of the Probable Project Costs (SCR Costs).

(2) Refer to Table 6-6 for a breakdown of the Probable Project Costs (Neural Network Costs).

(3) Refer to Table 6-7 for the Estimated Fixed O&M Costs.

(4) Refer to Table 6-9 for the Ammonia Costs. Values to calculate the ammonia cost per year were derived from the BREC 2007-2010 Work Plan Variable O&M.xls and BREC Production Cost Model 1-11-06.xls spreadsheets.

(5) Refer to Table 6-9. Based on information provided by BREC in spreadsheet entitled "2006 BREC Annual Budget.xls".

(6) Refer to Table 6-9. Based on information provided by BREC. The initial catalyst is assumed to last for 16,000 hours or 3 years. A new catalyst layer would be installed at the start of the fourth year and approximately every two years (or 12,000 hours) thereafter.

(7) Refer to Table 6-8 for the annual auxiliary power (kW) requirements. The values in Table 6-8 were derived from the S&L 1999 Study Appendix D. The auxiliary power costs were derived from the BREC 2007-2010 Work Plan (Green Exec summary.xls).

(8) The heat rate penalty amounts were derived from the S&L 1999 Study Appendix C.

(9) Financial information was provided by BREC.

(10) The energy generation was derived from the BREC Production Cost Model 1-11-06.xls Resource Report-Full.

(11) The fuel costs were derived from the BREC Production Cost Model 1-11-06.xls Fuel Report.

(12) The NO_X allowance price forecast amounts were derived from the "GII Allowance Forecasts 02-24-06.xls.

(13) The excess NO_X allowance tons for 2009 through 2023 are based on an average of the conservative amounts developed in the 2007 and 2008 Option 1 Sensitivity Case S1h model runs times a 12/5 ratio to account for the year round OTAG season.

(14) The excess NO_X allowance tons for 2009 through 2023 are based on an average of the amounts developed in the 2007 and 2008 Option 2 Base Case model runs times a 12/5 ratio to account for the year round OTAG season.

(15) The additional NO_X allowance tons needed for 2009 through 2023 are based on an average of the conservative amounts developed in the 2007 and 2008 Option 2 Sensitivity Case S1h model runs times a 12/5 ratio to account for the year round OTAG season.

(16) The additional NO_X allowance tons needed for 2009 through 2023 are based on an average of the conservative amounts developed in the 2007 and 2008 Wilson Unit Sensitivity Case S1h model runs times a 12/5 ratio to account for the year round OTAG season.

(17) The additional NO_X allowance tons needed for 2007 and 2008 are based on the conversative amounts developed in the 2007 and 2008 Wilson Unit Sensitivity Case S1h model runs.

(18) The additional NO_X allowance tons needed for 2009 through 2023 are based on an average of the conservative amounts developed in the 2007 and 2008 Base Case model runs times a 12/5 ratio to account for the year round OTAG season.

Table J-2
Present Value Analysis Summary

Option 1 - Install SCRs on Green Units 1 & 2

Total Project Capital Cost: $102,064,000

Year	Debt Service	Fixed & Variable Costs	Allowances Purchased/(Sold)	Total Annual Net Costs
2007	$0	$0	$1,755,726	$1,755,726
2008	$0	$0	$1,596,972	$1,596,972
2009	$6,899,785	$3,268,376	($3,228,524)	$6,939,637
2010	$6,899,785	$3,413,677	($3,039,114)	$7,274,348
2011	$6,899,785	$3,493,305	($2,799,602)	$7,593,488
2012	$6,899,785	$9,806,201	($2,375,568)	$14,330,418
2013	$6,899,785	$3,722,584	($2,145,832)	$8,476,537
2014	$6,899,785	$10,426,092	($1,753,570)	$15,572,306
2015	$6,899,785	$3,920,525	($1,369,862)	$9,450,447
2016	$6,899,785	$11,126,620	($1,408,966)	$16,617,439
2017	$6,899,785	$4,140,851	($1,446,848)	$9,593,788
2018	$6,899,785	$11,688,118	($1,487,174)	$17,100,728
2019	$6,899,785	$4,419,329	($1,516,502)	$9,802,612
2020	$6,899,785	$12,410,451	($1,545,830)	$17,764,405
2021	$6,899,785	$4,661,738	($1,556,828)	$10,004,695
2022	$6,899,785	$13,264,353	($1,452,958)	$18,711,180
2023	$6,899,785	$4,932,051	($1,412,632)	$10,419,203
Total 2007-2023 Costs	$103,496,770	$104,694,271	($25,187,112)	**$183,003,929**
Present Value of 2007-2023 Annual Costs:				**$85,822,592**

Option 2A - Install SCR on Green Unit 1

Total Project Capital Cost: $56,071,000

Year	Debt Service	Fixed & Variable Costs	Allowances Purchased/(Sold)	Total Annual Net Costs
2007	$75,140	$0	$1,755,726	$1,830,866
2008	$150,280	$0	$1,596,972	$1,747,252
2009	$3,790,541	$1,627,396	($1,207,394)	$4,210,543
2010	$3,790,541	$1,710,816	($1,136,559)	$4,364,799
2011	$3,790,541	$1,760,367	($1,046,987)	$4,503,921
2012	$3,790,541	$4,898,414	($888,408)	$7,800,548
2013	$3,790,541	$1,868,664	($802,492)	$4,856,713
2014	$3,790,541	$5,293,554	($655,795)	$8,428,301
2015	$3,790,541	$1,959,260	($512,297)	$5,237,504
2016	$3,790,541	$5,603,472	($526,921)	$8,867,093
2017	$3,790,541	$2,090,437	($541,088)	$5,339,891
2018	$3,790,541	$5,848,837	($556,169)	$9,083,210
2019	$3,790,541	$2,216,107	($567,137)	$5,439,511
2020	$3,790,541	$6,308,228	($578,105)	$9,520,664
2021	$3,790,541	$2,324,025	($582,218)	$5,532,348
2022	$3,790,541	$6,684,103	($543,373)	$9,931,271
2023	$3,790,541	$2,491,973	($528,292)	$5,754,223
Total 2007-2023 Costs	$57,083,543	$52,685,653	($7,320,537)	**$102,448,659**
Present Value of 2007-2023 Annual Costs:				**$49,176,373**

Option 2B - Install SCR on Green Unit 1

Total Project Capital Cost: $56,071,000

Year	Debt Service	Fixed & Variable Costs	Allowances Purchased	Total Annual Net Costs
2007	$75,140	$0	$1,755,726	$1,830,866
2008	$150,280	$0	$1,596,972	$1,747,252
2009	$3,790,541	$1,627,396	$607,660	$6,025,597
2010	$3,790,541	$1,710,816	$572,010	$6,073,368
2011	$3,790,541	$1,760,367	$526,930	$6,077,838
2012	$3,790,541	$4,898,414	$447,120	$9,136,076
2013	$3,790,541	$1,868,664	$403,880	$6,063,085
2014	$3,790,541	$5,293,554	$330,050	$9,414,146
2015	$3,790,541	$1,959,260	$257,830	$6,007,631
2016	$3,790,541	$5,603,472	$265,190	$9,659,204
2017	$3,790,541	$2,090,437	$272,320	$6,153,299
2018	$3,790,541	$5,848,837	$279,910	$9,919,289
2019	$3,790,541	$2,216,107	$285,430	$6,292,078
2020	$3,790,541	$6,308,228	$290,950	$10,389,719
2021	$3,790,541	$2,324,025	$293,020	$6,407,586
2022	$3,790,541	$6,684,103	$273,470	$10,748,114
2023	$3,790,541	$2,491,973	$265,880	$6,548,395
Total 2007-2023 Costs	$57,083,543	$52,685,653	$8,724,348	**$118,493,544**
Present Value of 2007-2023 Annual Costs:				**$57,793,767**

Option 3A - Purchase Additional NO_x Allowances Needed

Total Project Capital Cost: $0

Year	Debt Service	Fixed & Variable Costs	Allowances Purchased	Total Annual Net Costs
2007	$0	$0	$1,755,726	$1,755,726
2008	$0	$0	$1,596,972	$1,596,972
2009	$0	$0	$2,243,058	$2,243,058
2010	$0	$0	$2,111,463	$2,111,463
2011	$0	$0	$1,945,059	$1,945,059
2012	$0	$0	$1,650,456	$1,650,456
2013	$0	$0	$1,490,844	$1,490,844
2014	$0	$0	$1,218,315	$1,218,315
2015	$0	$0	$951,729	$951,729
2016	$0	$0	$978,897	$978,897
2017	$0	$0	$1,005,216	$1,005,216
2018	$0	$0	$1,033,233	$1,033,233
2019	$0	$0	$1,053,609	$1,053,609
2020	$0	$0	$1,073,985	$1,073,985
2021	$0	$0	$1,081,626	$1,081,626
2022	$0	$0	$1,009,461	$1,009,461
2023	$0	$0	$981,444	$981,444
Total 2007-2023 Costs	$0	$0	$23,181,093	**$23,181,093**
Present Value of 2007-2023 Annual Costs:				**$13,644,261**

Option 3B - Purchase Additional NO_x Allowances Needed

Total Project Capital Cost: $0

Year	Debt Service	Fixed & Variable Costs	Allowances Purchased	Total Annual Net Costs
2007	$0	$0	$1,755,726	$1,755,726
2008	$0	$0	$1,596,972	$1,596,972
2009	$0	$0	$4,499,326	$4,499,326
2010	$0	$0	$4,235,361	$4,235,361
2011	$0	$0	$3,901,573	$3,901,573
2012	$0	$0	$3,310,632	$3,310,632
2013	$0	$0	$2,990,468	$2,990,468
2014	$0	$0	$2,443,805	$2,443,805
2015	$0	$0	$1,909,063	$1,909,063
2016	$0	$0	$1,963,559	$1,963,559
2017	$0	$0	$2,016,352	$2,016,352
2018	$0	$0	$2,072,551	$2,072,551
2019	$0	$0	$2,113,423	$2,113,423
2020	$0	$0	$2,154,295	$2,154,295
2021	$0	$0	$2,169,622	$2,169,622
2022	$0	$0	$2,024,867	$2,024,867
2023	$0	$0	$1,968,668	$1,968,668
Total 2007-2023 Costs	$0	$0	$43,126,263	**$43,126,263**
Present Value of 2007-2023 Annual Costs:				**$24,356,422**

Stanley Consultants INC.
A Stanley Group Company
Engineering, Environmental and Construction Services - Worldwide

August 15, 2006

Mr. David Spainhoward
Vice President External Relations
& Interim Chief Production Officer
Big Rivers Electric Corporation
201 Third Street
P.O. Box 24
Henderson, KY 42419-0024

Dear Mr. Spainhoward:

Subject: WKE Status Quo Present Value Analysis

Attached is the present value analysis of Western Kentucky Energy (WKE) NO_x allowance purchases for the future years of the current lease arrangement. This projection assumes the current lease continues and is based on the NO_x allowances purchased during the historical years of 2004 and 2005. Stanley Consultants analyzed these purchases as a part of the activity of the WKE Compliance Plan Kentucky NO_x SIP Call Performance Review study.

This information is provided for your files. Please call if we can be of any further assistance.

Sincerely,

Stanley Consultants, Inc.

Ray R. Walters, P.E.

Enclosures

cc: Mike Thompson – BREC
Steve Schebler
Cathy Bermel
Files 15026

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internet: www.stanleyconsultants.com

WKE STATUS QUO
PRESENT VALUE ANALYSIS

Study Parameters (2006)			
Probable Project Costs (SCR Costs) (1)	$0	$0	$0
Probable Neural Network Costs (2)	$0	$0	$0
TOTAL PROJECT COST (Owner's Cost)	$0	$0	$0
Annual Fixed O&M (3)	$0	$0	$0

Variable O&M (2006):				
Anhydrous Ammonia ($/Ton) (4)	Refer to Notes			
Ammonia Consumption (Tons/MWh) (4)	0			
Emulsified Sulfur ($/year) (5)		$0	$0	$0
Catalyst Replacement (6)		$0	$0	$0
Annual Auxiliary power (kW) (7)		0	0	0
Auxiliary Power Price ($/MWh) (7)	Refer to Notes			
Heat Rate Penalty (Btu/kWh) (8)	Green 1 Green 2			

Financial Parameters (2006) (9)	
Interest Rate	5.75%
Financing Term (years)	34
Capital Recovery Factor	0.06760
Discount Rate	8.00%
Escalation Rate	3.00%

Year >>>>		2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2007-2023
Green Unit 1 MWh		1,850,001	1,859,000	1,823,000	1,880,000	1,855,000	1,671,000	1,861,000	1,864,000	1,822,000	1,847,000	1,849,000	1,685,000	1,852,000	1,861,000	1,814,000	1,853,000	1,859,000	31,085,000
Green Unit 2 MWh		1,830,000	1,679,000	1,813,000	1,800,000	1,756,000	1,787,000	1,790,000	1,654,000	1,788,000	1,798,000	1,741,000	1,771,000	1,793,000	1,632,000	1,800,000	1,796,000	1,746,000	29,974,000
Price of Ammonia ($/Ton)		$406.20	$426.87	$448.21	$470.62	$484.74	$499.28	$514.26	$529.69	$545.58	$561.94	$578.80	$596.17	$614.05	$632.47	$651.45	$670.99	$691.12	
Auxiliary Power Price ($/MWh)		$21.27	$21.57	$23.43	$24.17	$24.90	$25.64	$26.41	$27.20	$28.02	$28.86	$29.73	$30.62	$31.54	$32.48	$33.46	$34.46	$35.49	
Green Fuel Cost ($/mmBtu)		$1.123	$1.147	$1.223	$1.298	$1.342	$1.375	$1.407	$1.440	$1.469	$1.499	$1.530	$1.562	$1.593	$1.625	$1.660	$1.696	$1.732	
Emission Allowance Price ($/Ton) (1)		$2,459	$2,262	$2,642	$2,487	$2,291	$1,944	$1,756	$1,435	$1,121	$1,153	$1,184	$1,217	$1,241	$1,265	$1,274	$1,189	$1,156	
WKE STATUS QUE																			
Excess NO_x Allowances		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Additional NO_x Allowances Needed (2)(4)		495.5	495.5	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	1189.2	18,829
Debt Service		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Fixed O&M		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Variable O&M:	Ammonia	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Emulsified Sulfur	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Catalyst	..	-------	-------	-------	-------	0	-------	0	-------	0	-------	0	-------	0	-------	0	-------	0
	Auxiliary Power	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Heat Rate Penalty	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Sale of Excess NO_x Allowances		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of Additional NO_x Allowances Needed		1,218,435	1,120,821	3,141,866	2,957,540	2,724,457	2,311,605	2,088,235	1,706,502	1,333,093	1,371,148	1,408,013	1,447,256	1,475,797	1,504,338	1,515,041	1,413,959	1,374,715	30,113,022
Net Costs		$1,218,435	$1,120,821	$3,141,866	$2,957,540	$2,724,457	$2,311,605	$2,088,235	$1,706,502	$1,333,093	$1,371,148	$1,408,013	$1,447,256	$1,475,797	$1,504,338	$1,515,041	$1,413,959	$1,374,715	$30,113,022
Present Value of Net Costs	$17,005,850	$1,128,180	$960,923	$2,494,115	$2,173,880	$1,854,220	$1,456,829	$1,218,465	$921,970	$666,878	$635,107	$603,873	$574,725	$542,646	$512,168	$477,604	$412,721	$371,543	$17,005,850

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(1) The NO_x allowance price forecast amounts were derived from the "GII Allowance Forecasts 02-24-06.xls.

(2) The 2007 and 2008 Additional NO_x Allowances Needed is based on the average of the "2004 and 2005 Nox Actuals Compared to Budget" WKE spreadsheets. The 2004 actual tons of emissions were adjusted to reflect a five month OTAG season of May 1 through September 30 instead of the actual May 31 through September 30, 2004 OTAG season. The 495.5 tons of Additional NO_x Allowances Needed were determined as follows:

	2004	2005	2004-05 Average
Actual Tons of Emissions	4,796 (3)	5195	
Allocated NO_x Allowances	4500.0	4500	
Additional NO_x Allowances Needed	298	695	495.5

(3) The 3856 tons of actual 2004 emissions for the May 31 through September 30 OTAG season in 2004 was ratioed up from the 123 days (May 31 through Sept 30) to the 5 month OTAG season of 153 days (May 1 through September 30) as: ((153/123) times 3856) = 4796 tons

(4) The 2009 through 2023 Additional NO_x Allowances Needed were adjusted by 12/5 (or 2.4) to account for a 12 month OTAG season starting in 2009 instead of the current May 1 through September 30 OTAG season as: (495.5 times (12/5)) = 1189.2 tons.

CO2 EmissionsTax

CO2 emissions per unit per generation, etc

(using 1990 historical data)

	annual MWhrs net generation	service hours	coal burn TPY	avg unit MW output	annual net heat rate	coal BTU/lb	CO2 TPY	at tax of $1.00
C-1	1,088,230	8,000	1,399,707	136	9,935	11,178	1,118,912	$1,118,912
C-2	951,572	7,089		134	9,941	11,178	978,991	$978,991
C-3	1,079,927	8,000		135	10,204	11,178	1,140,436	$1,140,436
G-1	1,594,661	7,500	1,571,576	213	10,518	10,633	1,764,075	$1,764,075
G-2	1,559,331	7,400		211	10,677	10,633	1,751,069	$1,751,069
H-1	1,006,664	8,000	811,089	126	10,145	12,450	917,356	$917,356
H-2	975,905	7,900		124	10,230	12,450	896,776	$896,776
R-1	180,921	4,300	94,900	42	12,543	11,956	219,571	$219,571
W-1	2,555,765	7,800	1,196,503	328	10,110	10,800	2,829,107	$2,829,107
Total	10,992,976		5,073,775				11,616,293	$11,616,293

Sensativity:

									delta
W-1	3,044,000	7,607	1,430,228	400	10,807	11,000	3,536,376	$3,536,376	
					10,707	11,000	3,503,351	$3,503,351	($33,025)
					10,807	10,900	3,568,820	$3,568,820	$32,444

note: ~1.0 TPHr CO2/MW (not MWhr)

note: ~2.25 tons CO2 emitted per ton of coal burned.

note: for every one ton of carbon-C burned from the coal, 2.667 tons of oxygen-O from the air is combined.

note: ~1.1 TPHr CO2/MWhr

CO2 EmissionsTax

CO2 emissions per unit per generation, etc
(using 2012 from the 05-02-07 Henwood PCM run)

	annual MWhrs net generation	service hours	coal burn TPY	avg unit MW output	annual net heat rate	coal BTU/lb	CO2 TPY	at tax of $1.00
C-1	1,101,000	7,546	516,752	146	10,791	11,000	1,249,474	$1,249,474
C-2	1,023,000	8,050	536,752	127	12,071	11,000	1,298,666	$1,298,666
C-3	1,015,000	6,786	477,729	150	10,829	11,000	1,155,934	$1,155,934
G-1	1,786,000	7,871	982,291	227	10,997	11,000	1,996,798	$1,996,798
G-2	1,885,000	8,375	1,031,976	225	11,124	11,000	2,131,823	$2,131,823
H-1	1,184,000	8,050	557,402	147	10,832	11,600	1,236,440	$1,236,440
H-2	1,026,000	6,786	483,761	151	10,842	11,600	1,072,432	$1,072,432
R-1	39,000	7,283	22,780	5	13,551	11,600	55,580	$55,580
W-1	3,044,000	7,607	1,430,228	400	10,807	11,000	3,536,376	$3,536,376
Total	12,103,000		6,039,671				13,733,523	$13,733,523

Sensativity:

									delta
W-1	3,044,000	7,607	1,430,228	400	10,807	11,000	3,536,376	$3,536,376	
					10,707	11,000	3,503,351	$3,503,351	($33,025)
					10,807	10,900	3,568,820	$3,568,820	$32,444

note: ~1.0 TPHr CO2/MW (not MWhr)
note: ~2.25 tons CO2 emitted per ton of coal burned.
note: for every one ton of carbon-C burned from the coal, 2.667 tons of oxygen-O from the air is combined.
note: ~1.1 TPHr CO2/MWhr

CO2 EmissionsTax

CO2 emissions per unit per generation, etc

(delta between 2012 minus 1990 emissions)

	annual MWhrs net generation	service hours	coal burn TPY	avg unit MW output	annual net heat rate	coal BTU/lb	CO2 TPY	2012 at tax of $1.00
C-1	12,770			10	856	(178)	130,562	$130,562
C-2	71,428			(7)	2,130	(178)	319,675	$319,675
C-3	(64,927)			15	625	(178)	15,498	$15,498
G-1	191,339			14	479	367	232,723	$232,723
G-2	325,669			14	447	367	380,754	$380,754
H-1	177,336			21	687	(850)	319,084	$319,084
H-2	50,095			28	612	(850)	175,656	$175,656
R-1	(141,921)			(37)	1,008	(356)	(163,991)	($163,991)
W-1	488,235			72	697	200	707,269	$707,269
Total	1,110,024		965,896				2,117,230	$2,117,230

note: ~1.0 TPHr CO2/MW (not MWhr)
note: ~2.25 tons CO2 emitted per ton of coal burned.
note: for every one ton of carbon-C burned from the coal, 2.667 tons of oxygen-O from the air is combined.
note: ~1.1 TPHr CO2/MWhr

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
1	**I. Sales (TWH)**																			
2																				
3	Rural	2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																				
5	Large Industrial	0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																				
7	Century	-	-	-	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
8																				
9	Alcan	-	-	-	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
10																				
11	Market	1.16	0.71	-	1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
12																				
13	Total Sales	4.53	1.80	-	8.28	12.29	12.49	12.29	12.29	12.35	12.41	12.45	12.52	12.43	12.59	12.40	12.53	12.64	12.67	12.78
14																				

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:		4/30/2008	
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																			
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	24.24%	1.92%	2.73%	3.86%	2.02%	9.46%	0.00%	3.87%	1.28%	2.92%	0.64%	3.32%
FAC ($/ MWH)				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
PPA ($/ MWH)				(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
Environmental Surcharge Adjustment ($/ MWH)																			
Rural				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Large Industrial				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Smelters				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Rural																			
Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.52	9.34	9.52	9.78	10.16	10.36	11.34	11.34	11.78	11.93	12.28	12.36	12.77
Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.81	25.85	26.35	27.07	28.11	28.68	31.39	31.39	32.61	33.03	33.99	34.21	35.34
Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
GRA	-	-		-	-	-	0.74	9.92	10.82	12.12	14.01	15.04	19.95	19.94	22.13	22.87	24.61	24.99	27.03
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.16	0.53	0.89	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.75	46.03	53.06	56.42	59.53	61.68	65.99	66.52	69.29	70.75	72.93	74.15	76.46
TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.75	46.03	53.06	56.42	59.53	61.68	65.99	66.52	69.29	70.75	72.93	74.15	76.46
Large Industrial																			
Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.35	12.86	13.11	13.47	13.99	14.27	15.62	15.62	16.22	16.43	16.91	17.02	17.58
Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.99	17.38	17.71	18.20	18.90	19.28	21.11	21.11	21.92	22.20	22.85	23.00	23.76
Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
GRA	-	-		-	-	-	0.63	8.39	9.16	10.26	11.87	12.75	16.92	16.92	18.79	19.44	20.91	21.25	22.99
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.16	0.53	0.89	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	32.03	38.93	45.83	49.01	51.86	53.91	57.47	58.03	60.49	61.91	63.81	65.01	67.03
TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	32.03	38.93	45.83	49.01	51.86	53.91	57.47	58.03	60.49	61.91	63.81	65.01	67.03

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
75	GRA	-	-		-	-	-	0.71	9.45	10.30	11.54	13.34	14.31	18.99	18.98	21.06	21.77	23.42	23.78	25.73
76																				
77	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
78	Environmental Surcharge				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
81	Net				(0.00)	0.16	0.53	0.89	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.99	43.83	50.80	54.09	57.11	59.23	63.28	63.81	66.48	67.92	70.00	71.21	73.42
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.99	43.83	50.80	54.09	57.11	59.23	63.28	63.81	66.48	67.92	70.00	71.21	73.42
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	27.92	34.79	35.54	36.53	37.98	38.72	42.50	42.51	44.19	44.71	46.10	46.41	47.98
89	TIER Adjustment	-	-		-	-	-	1.77	2.59	2.58	2.57	3.16	3.15	3.14	2.29	3.73	3.72	4.31	4.30	4.29
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	29.69	37.38	38.11	39.10	41.14	41.87	45.64	44.80	47.91	48.43	50.41	50.71	52.27
91	FAC				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
92	PPA	-	-		(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
93	Environmental Surcharge				0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
94	Surcharge 1	-	-		0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2				1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	42.54	50.98	52.71	53.93	57.42	58.56	64.32	62.60	66.75	67.40	70.23	70.95	73.49
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	50.22	56.65	60.91	62.50	65.48	65.49	67.86	70.00	74.05	75.37	74.97	79.93	80.37
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	41.40	49.35	52.91	54.79	58.05	59.38	64.23	63.60	67.06	68.04	70.43	71.53	73.84
102																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
103	**III. Cash Flows (M$)**															Transaction Closing Date:			4/30/2008	
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	93.6	119.4	140.7	152.5	164.5	173.9	189.9	195.3	207.7	216.4	227.5	235.8	247.8
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	35.3	45.4	55.0	60.5	65.8	70.2	76.9	79.6	85.1	89.1	94.2	98.2	103.6
108	Smelters	-	-	-	171.7	257.7	277.7	303.7	373.0	384.6	393.5	419.0	428.5	469.3	456.8	487.1	493.2	512.5	517.7	536.3
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	66.3	68.6	73.0	73.2	73.1	70.9	62.1	69.0	51.5	54.1	56.1	54.7	56.2
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	4.0	3.808	3.8	4.1	4.3	4.6	5.1	5.7	6.1	6.6	7.1	7.4
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	505.2	611.4	658.5	684.5	717.4	739.5	795.5	798.1	830.3	851.2	888.9	905.5	942.7
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	227.1	228.3	238.5	245.1	246.0	253.5	252.0	257.3	252.9	262.2	266.4	268.0	271.2
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	30.8	30.5	36.8	29.6	33.8	33.7	53.3	37.1	51.3	45.2	51.5	55.6	65.8
122	Carbon Tax			-	-	-	-	-	92.6	104.6	119.7	133.2	146.8	155.3	174.4	182.0	199.6	214.5	226.5	241.3
123	Carbon Allowance Cost			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(6.5)	(0.3)	(1.3)	(2.2)	(1.5)	(1.8)	(0.4)	(2.2)	(1.5)	(2.6)	(1.3)	(2.6)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	436.1	528.5	569.1	582.5	615.1	635.5	684.7	681.1	714.8	734.5	772.7	792.0	828.8
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	82.9	89.5	102.0	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
136																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
137																Transaction Closing Date:			4/30/2008	
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	82.9	89.5	102.0	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	47.2	11.9	18.9	12.9	29.0	53.9	64.3	64.6	65.7	70.3	70.9	68.0	71.1	68.3	66.1	64.6
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	Post-Finance Cash Flow	42.0	(3.5)	-	8.1	(46.5)	(39.5)	(45.5)	(29.4)	(4.5)	5.9	6.2	7.3	11.9	12.5	9.6	12.7	9.9	7.7	6.2
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	20.4	24.2	4.5	-	-	-	-	-	-	-	-	-	-
167	Net Before Transition Reserve			25.1	5.5	12.5	19.1	20.4	24.2	4.5	-	-	-	-	-	-	-	-	-	-
168																				
169	Ending Cash Balances (Incl. Transition Reserve)	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.0	88.9	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6	178.8
170																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
171	**IV. Income Statement (M$)**																			
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.5	87.1	88.8	96.0	119.4	140.7	152.5	164.5	173.9	189.9	195.3	207.7	216.4	227.5	235.8	247.8
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	36.2	45.4	55.0	60.5	65.8	70.2	76.9	79.6	85.1	89.1	94.2	98.2	103.6
176	Smelters	-	-	-	170.6	254.9	275.0	310.4	373.0	384.6	393.5	419.0	428.5	469.3	456.8	487.1	493.2	512.5	517.7	536.3
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	66.3	68.6	73.0	73.2	73.1	70.9	62.1	69.0	51.5	54.1	56.1	54.7	56.2
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
181	*WKEC Lease (Net)*	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	4.031	3.808	3.805	4.056	4.323	4.637	5.146	5.681	6.092	6.638	7.060	7.388
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	514.6	610.9	658.0	684.0	716.9	738.9	794.9	797.6	829.8	850.7	888.3	904.9	942.1
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	27.9	33.1	28.2	31.0	33.6	46.3	35.7	47.4	43.4	47.4	53.0	59.4
189	Carbon Tax			-	-	-	-	-	92.6	104.6	119.7	133.2	146.8	155.3	174.4	182.0	199.6	214.5	226.5	241.3
190	Carbon Allowance Cost			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
192	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	519.1	619.1	646.5	668.0	700.9	722.9	778.8	781.5	813.6	834.4	872.1	888.6	925.7
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	20.4	24.2	4.5	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
210																				
211	**V. Balance Sheet (M$)**																	Transaction Closing Date:		4/30/2008
212																				
213	Assets																			
214	Property																			
215	Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216	Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217	Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218	Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219	Current																			
220	Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	53.4	46.4	44.5	48.5	52.7	58.0	67.7	78.0	85.3	95.6	102.9	107.9	111.3
222	Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223	Economic Reserve	-	-	75.0	71.6	62.1	45.7	27.3	4.3	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	42.5	50.6	54.5	56.7	59.4	61.2	65.9	66.0	68.7	70.4	73.5	74.8	77.9
225	Regulatory Asset	-	-	-	-	-	-	0.3	2.9	6.6	8.0	10.8	11.0	18.0	19.4	23.3	25.1	29.1	31.7	38.1
226	Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4
227	Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228	Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229	Credits																			
230	AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231	Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232	Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233	Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234	LEM Settlement Note/Marketing Paymer	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Total Assets	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,593.4	1,600.6	1,611.2	1,623.0	1,633.0	1,646.0	1,652.9	1,663.8	1,673.0	1,684.4	1,692.5	1,703.7
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	432.5	448.5	464.4	480.4	496.4	512.5	528.6	544.7	560.8	577.1	593.3	609.7	626.1
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241	Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242	Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243	Current & Accrued Liabilities																			
244	Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	63.1	77.6	81.6	84.8	89.5	92.7	98.9	99.2	103.9	106.9	112.4	114.8	120.2
245	Regulatory Liability				1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247	Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	27.3	4.3	-	-	-	-	-	-	-	-	-	-	-
248	Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249	Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250	Deferred TIER Rebate Payable				1.7	5.8	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
251	WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252	Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253	Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,593.4	1,600.6	1,611.2	1,623.0	1,633.0	1,646.0	1,652.9	1,663.8	1,673.0	1,684.4	1,692.5	1,703.7
255																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	2.9	8.1	3.9	2.2	2.7	1.8	4.6	0.2	2.6	1.7	3.1	1.3	3.1
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	(4.0)	(14.5)	(4.0)	(3.3)	(4.7)	(3.1)	(6.2)	(0.3)	(4.7)	(3.0)	(5.5)	(2.4)	(5.4)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(6.5)	(0.3)	(1.3)	(2.2)	(1.5)	(1.8)	(0.4)	(2.2)	(1.5)	(2.6)	(1.3)	(2.6)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.0	88.9	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6
272	Ending	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.0	88.9	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6	178.8
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	Plus: Imputed Rate Increase in 2010				-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
282	Total				40.7	60.5	59.8	59.0	58.3	57.4	56.4	55.4	54.5	53.4	52.2	51.1	49.9	48.5	47.3	45.6
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
291																				
292	Conventional TIER																			
293	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	60.7	60.0	59.9	59.0	58.1	57.3	56.3	55.3	54.2	53.1	51.9	50.9	49.3
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	75.2	75.1	75.5	75.3	75.1	75.0	74.8	74.7	74.6	74.5	74.3	74.4	74.0
299	Divided by																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31
305																				

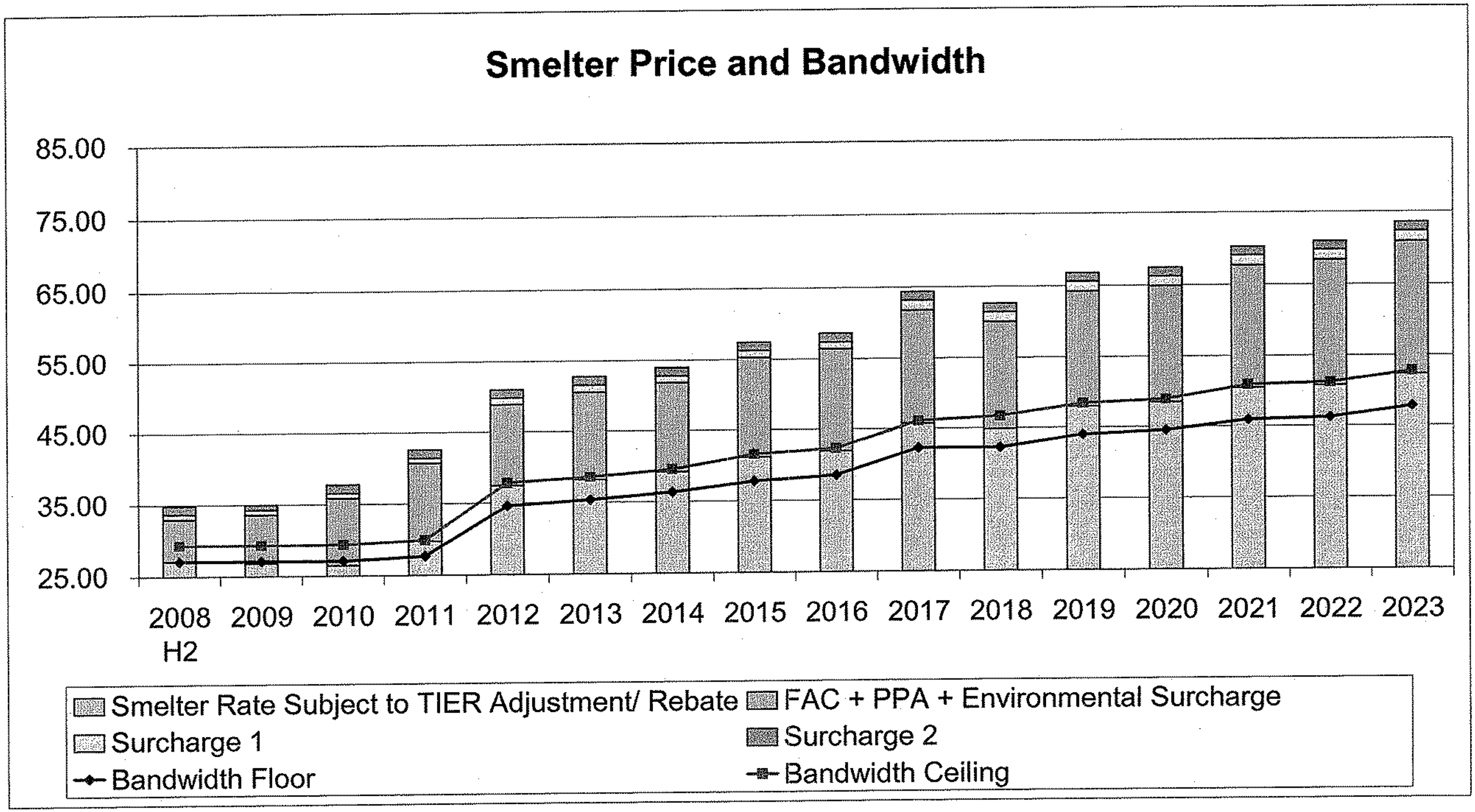
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
306	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
307	Cash Available for Debt Service																			
308	Receipts less Disbursements				84.6	88.0	77.5	69.2	82.9	89.5	102.0	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
309	Economic Reserve				5.5	12.5	19.1	20.4	24.2	4.5	-	-	-	-	-	-	-	-	-	-
310	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
311	Net				90.2	100.5	96.6	89.5	107.1	93.9	101.7	101.9	103.5	110.3	116.6	115.1	116.3	115.6	113.0	113.3
312	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
313	Total				99.1	113.8	110.5	104.0	122.1	109.6	118.0	119.0	121.3	128.9	136.0	135.5	137.6	138.0	136.5	138.0
314	Divided by																			
315	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
316	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
317	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
318	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
319																				
320	*DSCR*				2.06	1.59	1.53	1.43	1.66	1.48	1.58	1.58	1.59	1.67	1.75	1.72	1.73	1.71	1.67	1.66
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	106.7	91.6	88.9	91.8	97.9	104.7	114.3	126.5	137.5	148.7	160.0	168.8	175.7
324	Line of Credit				66.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
325	Total	117.5	136.7	147.5	233.8	256.6	229.5	206.7	191.6	188.9	191.8	197.9	204.7	214.3	226.5	237.5	248.7	260.0	268.8	275.7
326	Divided by																			
327	Total Operating Expense																			
328	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
330	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	27.9	33.1	28.2	31.0	33.6	46.3	35.7	47.4	43.4	47.4	53.0	59.4
331	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
332	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
333	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
334	APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
335	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
336	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
337	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
338	Total	182.8	69.2	-	293.6	439.0	450.9	477.3	483.2	497.9	504.2	522.0	528.8	562.1	544.2	567.5	569.3	590.6	593.5	614.4
339																				
340	*Days Cash on Hand (including Line o.*	234.5	721.0		290.6	213.4	185.8	158.1	144.7	138.5	138.9	138.4	141.3	139.2	151.9	152.8	159.5	160.7	165.3	163.8
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		207.4	130.2	104.8	81.6	69.2	65.2	66.5	68.4	72.2	74.2	84.8	88.5	95.3	98.9	103.8	104.4
342																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	Beginning Principal		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	859.1	851.2	839.0	826.0	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

Smelter Rate Structure

December 2007

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	2.00%	24.24%	1.92%	2.73%	3.86%	2.02%	9.46%	0.00%	3.87%	1.28%	2.92%	0.64%	3.32%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
3 Alcan	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
4 Total Energy (TWh)	4.898	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297
5 Total Demand (GW)	6.847	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	12.86	13.11	13.47	13.99	14.27	15.62	15.62	16.22	16.43	16.91	17.02	17.58
13 Energy ($/ MWH)	13.72	13.72	13.72	13.99	17.38	17.71	18.20	18.90	19.28	21.11	21.11	21.92	22.20	22.85	23.00	23.76
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
17 Less: Regulatory Account Charge	-	-	-	-	-	(0.25)	(0.25)	(0.24)	(0.87)	(0.85)	(0.84)	(1.47)	(1.44)	(1.41)	(2.07)	(2.03)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	31.13	38.93	39.70	40.83	42.45	43.36	47.54	47.55	49.44	50.13	51.59	51.94	53.70
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.67	34.54	35.29	36.28	37.73	38.47	42.25	42.26	43.94	44.46	45.85	46.16	47.73
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.92	34.79	35.54	36.53	37.98	38.72	42.50	42.51	44.19	44.71	46.10	46.41	47.98
23 Plus TIER Adjustment	-	-	-	1.77	2.59	2.58	2.57	3.16	3.15	3.14	2.29	3.73	3.72	4.31	4.30	4.29
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	29.69	37.38	38.11	39.10	41.14	41.87	45.64	44.80	47.91	48.43	50.41	50.71	52.27
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	10.95	11.40	12.40	12.62	14.08	14.49	16.08	15.21	16.24	16.38	17.23	17.64	18.63
28 Plus Surcharge 1	0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
29 Plus Surcharge 2	1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	42.54	50.98	52.71	53.93	57.42	58.56	64.32	62.60	66.75	67.40	70.23	70.95	73.49
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	27.92	34.79	35.54	36.53	37.98	38.72	42.50	42.51	44.19	44.71	46.10	46.41	47.98
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	29.87	37.74	38.49	39.48	41.53	42.27	46.05	46.66	48.34	48.86	50.85	51.16	52.73
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	29.69	37.38	38.11	39.10	41.14	41.87	45.64	44.80	47.91	48.43	50.41	50.71	52.27


Smelter Price and Bandwidth
85.00
75.00
65.00
55.00
45.00
35.00
25.00
2008 H2
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Smelter Rate Subject to TIER Adjustment/ Rebate
FAC + PPA + Environmental Surcharge
Surcharge 1
Surcharge 2
Bandwidth Floor
Bandwidth Ceiling

Smelter Rate Structure

December 2007

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	132.2	164.8	195.7	213.0	230.3	244.1	266.8	274.9	292.8	305.5	321.7	334.0	351.4
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	297.5	354.1	365.8	374.8	396.0	405.4	446.4	440.1	459.9	466.0	481.1	486.4	505.0
Other Revenues	75.8	115.1	102.9	92.4	97.2	82.1	77.4	67.6	66.3	58.8	65.8	49.9	51.9	54.1	53.2	54.5
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	522.1	616.1	643.7	665.2	693.8	715.9	772.0	780.9	802.6	823.5	856.9	873.6	910.8
Total Expenses	315.2	473.3	486.4	519.1	619.1	646.5	668.0	700.9	722.9	778.8	781.5	813.6	834.4	872.1	888.6	925.7
Net Margin Before TIER Adjustment	12.3	21.7	23.3	3.0	(3.0)	(2.8)	(2.8)	(7.1)	(7.0)	(6.9)	(0.6)	(11.0)	(11.0)	(15.2)	(15.0)	(14.9)
Interest + Margin	52.4	81.2	82.7	62.3	56.2	56.1	55.9	51.4	51.3	51.2	57.2	46.6	46.4	42.0	42.1	41.8
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	1.05	0.95	0.95	0.95	0.88	0.88	0.88	0.99	0.81	0.81	0.73	0.74	0.74
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	11.2	17.2	17.0	16.8	21.1	21.0	20.8	14.4	24.8	24.8	28.9	28.7	28.5
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
Less: Offset to Imputed Rate Increase in 2010	-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Total Adjustments	(1.0)	(1.5)	0.9	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	12.9	18.9	18.8	18.7	23.1	23.1	22.9	16.7	27.2	27.2	31.4	31.4	31.3
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	12.9	18.9	18.8	18.7	23.1	23.1	22.9	16.7	27.2	27.2	31.4	31.4	31.3
Rebate to Members/Smelters ($/MWh)																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	-	-	-	1.77	2.59	2.58	2.57	3.16	3.15	3.14	2.29	3.73	3.72	4.31	4.30	4.29

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.52	9.34	9.52	9.78	10.16	10.36	11.34	11.34	11.78	11.93	12.28	12.36	12.77
10	Energy ($/ MWH)	20.40	20.40	20.40	20.81	25.85	26.35	27.07	28.11	28.68	31.39	31.39	32.61	33.03	33.99	34.21	35.34
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
14	GRA	-	-	-	0.74	9.92	10.82	12.12	14.01	15.04	19.95	19.94	22.13	22.87	24.61	24.99	27.03
15	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
16	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
20	Net	(0.00)	(0.01)	(0.02)	(0.04)	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
21	Effective Rate	36.07	36.11	36.09	36.82	46.03	53.06	56.42	59.53	61.68	65.99	66.52	69.29	70.75	72.93	74.15	76.46
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	12.86	13.11	13.47	13.99	14.27	15.62	15.62	16.22	16.43	16.91	17.02	17.58
26	Energy ($/ MWH)	13.72	13.72	13.72	13.99	17.38	17.71	18.20	18.90	19.28	21.11	21.11	21.92	22.20	22.85	23.00	23.76
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
30	GRA	-	-	-	0.63	8.39	9.16	10.26	11.87	12.75	16.92	16.92	18.79	19.44	20.91	21.25	22.99
31	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
32	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
36	Net	(0.00)	0.02	0.06	0.09	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
37	Effective Rate	30.58	30.48	30.54	31.22	38.93	45.83	49.01	51.86	53.91	57.47	58.03	60.49	61.91	63.81	65.01	67.03
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
43	GRA	-	-	-	0.71	9.45	10.30	11.54	13.34	14.31	18.99	18.98	21.06	21.77	23.42	23.78	25.73
44	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
45	Env. Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(6.42)	(1.16)	-	-	-	-	-	-	-	-	-	-
49	Net	(0.00)	0.00	0.00	0.00	0.00	5.87	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
50	Effective Rate	34.44	34.40	34.39	35.10	43.83	50.80	54.09	57.11	59.23	63.28	63.81	66.48	67.92	70.00	71.21	73.42
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	(6.67)	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	2.69	2.65	4.63	2.40	3.77	3.78	10.59	5.04	10.39	8.21	10.54	12.23	16.11
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	(2.69)	(2.65)	(4.63)	(2.40)	(3.77)	(3.78)	(10.59)	(5.04)	(10.39)	(8.21)	(10.54)	(12.23)	(16.11)
8	Total	1.26	(0.17)	1.33	(2.69)	(2.65)	(4.63)	(2.40)	(3.77)	(3.78)	(10.59)	(5.04)	(10.39)	(8.21)	(10.54)	(12.23)	(16.11)
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						0.97	0.97	0.97	3.60	3.60	3.60	6.47	6.47	6.47	9.71	9.71
12	Debit Power Purchase Expense						0.97	0.97	0.97	3.60	3.60	3.60	6.47	6.47	6.47	9.71	9.71
13																	
14	Net Income	(1.26)	0.17	(1.33)	2.69	2.65	4.63	2.40	3.77	3.78	10.59	5.04	10.39	8.21	10.54	12.23	16.11
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						0.97	1.94	2.91	6.51	10.11	13.71	20.18	26.65	33.12	42.83	52.55
19	Regulatory Asset	-	-	-	0.27	2.91	6.57	8.00	10.79	10.98	17.97	19.41	23.34	25.07	29.14	31.65	38.05
20	Total	-	-	-	0.27	2.91	7.54	9.94	13.71	17.49	28.07	33.12	43.51	51.72	62.26	74.48	90.60
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	0.3	2.9	7.5	9.9	13.7	17.5	28.1	33.1	43.5	51.7	62.3	74.5	90.6
24	Regulatory Liability	1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	0.3	2.9	7.5	9.9	13.7	17.5	28.1	33.1	43.5	51.7	62.3	74.5	90.6

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.6	11.7	11.6	11.9	11.9	12.0	11.6	12.0	11.6	11.9	11.9	11.9	11.9
2	**Sales (TWh)**	8.3	12.3	12.5	12.3	12.3	12.3	12.4	12.4	12.5	12.4	12.6	12.4	12.5	12.6	12.7	12.8
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold	16.62	16.56	17.77	18.31	18.53	19.03	19.71	19.72	20.13	20.17	20.47	20.35	20.83	21.02	21.10	21.16
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	30.53	30.17	36.47	29.28	33.43	33.42	52.97	36.80	50.97	44.82	51.13	55.23	65.43
13																	
14	Total Costs for Passthrough ($/ MWh Sold	1.21	1.80	1.38	2.48	2.45	2.95	2.36	2.69	2.67	4.26	2.92	4.11	3.58	4.04	4.36	5.12
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
20																	
21	Total Costs for Passthrough ($/ MWh Sold	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/M	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
29	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
30	**Total**	6.39	6.69	9.73	10.22	10.70	11.20	12.01	13.15	13.58	13.57	14.04	13.88	14.56	14.93	15.04	15.26
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
33	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
34	**Total**	6.39	6.69	9.73	10.22	10.70	11.20	12.01	13.15	13.58	13.57	14.04	13.88	14.56	14.93	15.04	15.26
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
37	PPA	(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
38	Environmental Surcharge	0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
39	**Total**	5.85	6.74	9.36	10.95	11.40	12.40	12.62	14.08	14.49	16.08	15.21	16.24	16.38	17.23	17.64	18.63

UW Transaction

	($M)	2007	2008H1	Transaction	2008 H2
			0		0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	1. Cash Payment/ Credit Escrow Draws	-	-	301.5	-
2	2. WKE Residual Value Obligation				
3	WKE Gen. Capex - Cum.				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	3. LG&E Rental Income Advance				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	4. Fuel & Other Inventories	-	-	55.0	-
20	5. Cancellation of Settlement Prom. Note	-	-	16.0	-
21	6. Coleman Scrubber Completion	-	-	97.5	-
22	7. LG&E Emissions Allowance	-	-	10.9	-
23	8. Expense Unamortized Mktg Payment/ Settlement Note			(15.7)	
24	9. Assurances Agreement	-	-	4.3	-
25					
26	Total Residual Value Obligation	154.1	161.8	161.8	-
27	Cancellation of RV Obligation				
28	Reclassification as Equity	-	-	161.8	-
29					
30	Net WKE Obligation	154.1	161.8	-	-
31					

UW Transaction

	($M)		2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
32						
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction				134.9	
35	Transaction Proceeds				301.5	
36	Smelter Payment (Assurances Agreement)				(4.3)	
37	Consent Fee to Lease-Equity Parties				-	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				(0.3)	
41	Income Tax				(1.1)	
42	Net Transaction Cash				295.9	
43	Debt Restructuring:					
44	Debt Reduction (Net)				(186.2)	
45	Underwriting Costs	1.75%			(4.6)	
46	Bond Insurance	0.80%			(5.0)	
47	ARVP Defeasance Premium				-	
48	Total				(195.8)	
49	Restricted Cash Balances:					
50	Transition Reserve				(35.0)	
51	Economic Reserve				(75.0)	
52	Unrestricted Cash Balances Post-Transaction				125.0	
53						
54	**C. Debt Restructuring:**					
55	Beginning Balance - GAAP				1,051.1	
56	Cancellation of Settlement Prom. Note				(16.0)	
57	Capitalize Accrued Interest on RUS New Note				7.2	
58	Step-Up RUS New Note to Stated Basis:					
59	GAAP RUS New Note					
60	Ending Balance				791.4	
61	Accrued Interest				7.2	
62	Total				798.6	
63	Stated RUS New Note					
64	Ending Balance				794.7	
65	Accrued Interest				7.0	
66	Total				801.7	
67	Step-Up				3.1	
68	Beginning Balance - Stated				1,045.3	
69	Cash Flow:					
70	Prepay RUS New Note				(449.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				263.5	
73	Net				(186.2)	
74	Ending Balance - Stated				859.2	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.3)	
76	Ending Balance - GAAP				857.8	
77						

UW Transaction

			2007	2008H1	Transaction	2008 H2
	($M)			0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				
121						
122	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
123						
124	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
125						
126	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production-Fixed

Production - Fixed

	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	**Depreciation**																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	Blended Depreciation Adj.		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																			
2	Beginning Balance			-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest			-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service			(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																				
9	Fixed/ Insured (Tranche 2)																			
10	Beginning Balance			-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)			0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest			-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service			(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																				
17	RUS -- GAAP																			
18	Beginning Balance			791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon			0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)			0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest			-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest			440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service			440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																				
25	Variable																			
26	Beginning Balance			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon			0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																				
33	PCB																			
34	Beginning Balance			142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon			0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal			-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																				
41	ARVP																			
42	Beginning Balance			101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%		5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	Total																			
52	Beginning Balance			1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal			177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service			177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance			857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																				

Unwind Debt

($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
59 Supporting Schedules		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
60 Amortization of Financing Costs																			
61 Fixed/ Insured (Tranche 1)																			
62 Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63 BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64 YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65 Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66 *Accretion*			-	*0.0*	*0.1*	*0.1*	*0.1*	*0.1*	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67 EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																			
69 Fixed/ Insured (Tranche 2)																			
70 Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71 BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72 YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73 Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74 Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75 EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																			
77 Variable																			
78 Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79 BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80 YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81 Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82 Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83 EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																			
85																			
86 *Amortization of Financing Costs*																			
87 Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88 Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89 Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																			
91 Interest Expense																			
92 Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93 ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94 Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95 AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96 Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97 Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

December 2007

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	Defeasance Income	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	Additions	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

Income Taxes

December 2007

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	Non-Incremental	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476)	0	0
				185,791,428		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

	Electricity Sales, Purchases, and Production	Source:	005/ Othe	2006	2007	2008H1	Transactio 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	<u>Sales</u>																						
2	Rural																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	366	366	366	366	366	366	366	366	366	366	366	366	366	366
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.18						2.789	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
18																							
19	Offsystem (TWh)	file: annual output - 12-15-07.xls		1.93	1.16	0.71		1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
20																							
21	<u>Purchases & Production</u>																						
22	Purchases (TWh)																						
23	Market	file: annual output - 12-15-07.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.46	0.38	0.54	0.37	0.42	0.42	0.72	0.47	0.66	0.53	0.55	0.62	0.71
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 12-15-07.xls			-	-		8.07	11.80	12.10	11.63	11.71	11.65	11.88	11.87	11.95	11.56	11.97	11.58	11.86	11.94	11.90	11.92
26	Loss Rate (%)	file: annual output - 12-15-07.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	<u>Fuel Consumption (MMBtu)</u>	file: annual output - 12-15-07.xls						89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
29																							
30	<u>Startup Costs (M$)</u>	file: annual output - 12-15-07.xls			-	-		4.36	6.54	6.84	7.89	6.54	6.91	7.01	6.17	6.97	8.06	6.81	8.66	7.68	7.68	8.42	8.22
31																							
32	<u>Emissions</u>																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		14,032	18,797	19,882	18,824	19,356	18,298	19,317	20,336	20,806	19,359	20,823	18,767	19,356	20,501	20,755	20,354
35	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	17,125	17,125	18,352	18,352	18,352
36	NOX																						
37	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		4,932	13,610	13,606	12,916	12,895	13,063	12,974	13,115	12,988	13,014	13,060	12,813	13,164	13,188	12,936	13,288
38	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		4,651	11,072	11,072	11,071	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	<u>Rates</u>																						
42	Fuel ($/ MMBtu)	file: annual output - 12-15-07.xls						1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 12-15-07.xls		67.8347	77.90	200.00		47.55	53.53	53.88	51.18	56.64	52.87	57.00	60.16	60.86	62.71	60.84	64.42	68.93	77.34	75.00	79.88
46	Variable Production ($/ MWh sales)	file: annual output - 12-15-07.xls			-	2.27		2.27	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
47	SO2 Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	778		778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 12-15-07.xls	100%					4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
51																							
52	**Sales Rates & Related**																						
53																							
54	<u>General Rate Adjustments (%)</u>	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	2.00%	24.24%	1.92%	2.73%	3.86%	2.02%	9.46%	0.00%	3.87%	1.28%	2.92%	0.64%	3.32%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	<u>Market ($/ MWh)</u>	file: annual output - 12-15-07.xls		43.30	42.91	37.82		48.40	51.34	49.47	50.22	56.65	60.91	62.50	65.48	65.49	67.86	70.00	74.05	75.37	74.97	79.93	80.37
57																							
58	<u>Rural</u>																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	<u>Large Industrial</u>																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	<u>Smelters</u>																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	1.77	2.59	2.58	2.57	3.16	3.15	3.14	2.29	3.73	3.72	4.31	4.30	4.29
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	5.11	7.30	7.30	7.30	7.30	7.30	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																							
74	<u>Member Revenue Discount Adjustment (M$)</u>	Amortization of Gain on Year 2000 Sale-Leaseback transaction		3.68	3.68000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	<u>Power Factor Penalty/ Demand Cr. (Lrg. Ind.)</u>	Big Rivers Assumption		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	<u>TIER Rebate Related to Rurals ($M)</u>	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	(0.00)	-	-	-	-	-	-	-	-	-	-	-
79	<u>TIER Rebate Related to Large Industrials ($M)</u>	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	(0.00)	(0.00)	0.00	-	-	-	-	-	-	-	-	-	-
80	<u>TIER Rebate Related to Smelters ($M)</u>	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	<u>FAC Base, 12/2004 ($/ MWh Sold)</u>																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84	Allocation of Revenues on '																						
85	**Total**																						
86	NOx + SO3	file: annual output - 12-15-07.xls																					
87	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
89	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
91	Net Allowances	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
92	Total	file: annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
93	**Allowed In ES**																						
94	NOx + SO3	file: annual output - 12-15-07.xls																					
95	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
97	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
99	Net Allowance Costs in Excess of 2009	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
100	Total	file: annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates. 4/23/2007, Goldmen Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates. 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Lev				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007 xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances		-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.16																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.66	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.19	11.41	12.77	-	25.85															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

		Source:	2005/ Othe	2006	2007	2008H1	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	16.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.83	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	Net Confomring Receipts	Big Rivers' estimate		-	15.00	-																	
189	Cobank Patronage Capitel - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capitel (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.63	38.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (Includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Adjustment (8/2007)			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.48	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet — 8-29-07_Rev1.xls						3.88	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.61	13.60	4.66		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	Property Tax			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	6.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.26	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

272		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Cmn FGD Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	Phase I	Per Crockett Memo dated 11/12/07		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-			3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-		-															
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	-
307	Green River Coal Settlement	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson	file: annual output - 12-15-07 xls		-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.11)	(20.39)	(24.16)	(4.46)	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.28%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,760.4	1,780.2																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	826.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	Historic Balance Sheet	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	Credit Escrow	Economic Reserve	-	-	-	-	75.0	71.6	62.1	45.7	27.3	4.3	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	Long-Term Debt																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

Inputs

December 2007

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.35	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	27.3	4.3	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	1.2	0.2	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(20.4)	(24.2)	(4.5)	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	27.3	4.3	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 12-15-07.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	Depreciation																						

454		Source:		005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
455	Additional Book Depreciation																							
456	Prior year non-incremental + in service	Historic			12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic			6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE	Historic depreicatron rate			0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)			1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study		38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study		38																				
462																								
463																								
464	HMP&L Station Two																							
465	Prior year non-incremental	Historic			12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate			0.00	0.00	0.09		0.00															
467																								
468	Other																							
469	Prior year	Historic			6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate			0.00	0.00	0.00		0.00															
471																								
472	Book Depreciation & Amortization																							
473	Generation																							
474	Big Rivers' Plants	Historic			25.38	25.39	8.58		26.58	9.01														
475	HMP&L Station Two	Historic			1.58	1.64	0.54		0.93	0.31														
476	Other	Historic			5.05	5.25	1.75		5.06	1.69														
477																								
478	Adjustment to Depreciation																							
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3 10		0																				
480	Income Tax Related								0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
481																								
482	Previously Expensed Marketing Payment	Historic			0	0	0	4,196																
483																								
484	Status Quo Depreciation	Proforma		23.69																				
485																								
486	WKE Share of Capex																							
487	Non-Incremental	Participation Agreement - Cost Sharing			51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing			0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep				0.80	0.00	0.00																	
490	Temporary Differences																							
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic		149.87																				
492	Other Temporary Differences	Historic		19.65																				
493																								
494	NOL Related																							
495	Year				1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																								
497	Tax Rates																							
498	Regular	Big Rivers' estimate		35%																				
499	AMT	Big Rivers' estimate		20%																				
500																								
501	ACE																							
502	ACE Deduction				(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %			75%																				
504																								
505	SQ Addition	Historic			0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB				4.28	4.69	5.58	5.70																
507																								
508	Nonpatronage MWH	Historic		1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																					
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																					
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																					
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																					
513																								
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year							-	-	-	-	7.91	8.96	10.07	11.22	12.29	13.44	14.57	15.71	16.83	17.97	19.04	20.24
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Fuel Inventory

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,100	10,999	11,019	11,045	11,021	11,060	11,069	11,037	11,015	11,028	11,021	11,037	11,003
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.20	22.00	22.04	22.09	22.04	22.12	22.14	22.07	22.03	22.06	22.04	22.07	22.01
7	Coal Consumed {from PCM (000s tons)}		4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(129,052)	(129,383)	(128,057)	(130,536)	(130,460)	(131,239)	(127,332)	(131,626)	(127,278)	(130,423)	(131,329)	(130,729)	(131,111)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6
19	Fuel Purchased	-	133.3	197.7	220.4	219.2	221.7	231.6	238.1	239.8	246.5	244.0	250.5	244.3	254.5	258.8	259.6	263.0
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(217.2)	(221.2)	(228.1)	(237.6)	(239.3)	(245.0)	(242.6)	(250.9)	(243.7)	(253.3)	(258.1)	(259.0)	(262.3)
22	EB	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4

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December 2007

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	*0.000*	*0.000*	*1.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**I. Sales (TWH)**																			
2																Transaction Closing Date:			4/30/2008	
3	Rural	2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																				
5	Large Industrial	0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																				
7	Century	-	-	-	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
8																				
9	Alcan	-	-	-	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
10																				
11	Market	1.16	0.71	-	1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
12																				
13	Total Sales	4.53	1.80	-	8.28	12.29	12.49	12.29	12.29	12.35	12.41	12.45	12.52	12.43	12.59	12.40	12.53	12.64	12.67	12.78
14																				

	Calendar Year	2007	2008H1	Transac tion	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
15	**II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)**															Transaction Closing Date:			4/30/2008	
16																				
17	General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18																				
19	FAC ($/ MWH)				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
20																				
21	PPA ($/ MWH)				(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
22																				
23	Environmental Surcharge Adjustment ($/ MWH)																			
24	Rural				0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
25	Large Industrial				0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
26	Smelters				0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
27																				
28	Rural																			
29	Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
30	Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.52	7.52	8.33	8.33	8.33	8.33	8.33	8.33	8.33
31	Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.81	20.81	20.81	20.81	20.81	20.81	23.06	23.06	23.06	23.06	23.06	23.06	23.06
32																				
33	Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
34	MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
35	Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
36	GRA	-	-		-	-	-	0.74	0.74	0.74	0.74	0.74	0.74	4.83	4.83	4.82	4.82	4.82	4.82	4.81
37																				
38	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
39	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
40	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
41	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
42	Net	-	-		(0.00)	0.16	0.53	0.89	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
43																				
44	Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.75	43.25	52.61	54.68	56.96	59.12	63.36	65.26	66.66	68.62	70.11	71.86	73.12
45	TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.75	43.25	52.61	54.68	56.96	59.12	63.36	65.26	66.66	68.62	70.11	71.86	73.12
47																				
48	Large Industrial																			
49	Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
50	Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.35	10.35	11.47	11.47	11.47	11.47	11.47	11.47	11.47
51	Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.99	13.99	13.99	13.99	13.99	13.99	15.50	15.50	15.50	15.50	15.50	15.50	15.50
52																				
53	Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
54	Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
56	Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
57	GRA	-	-		-	-	-	0.63	0.63	0.63	0.63	0.63	0.63	4.10	4.10	4.10	4.10	4.10	4.10	4.10
58																				
59	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
60	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
61	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
62	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
63	Net	-	-		(0.00)	0.16	0.53	0.89	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
64																				
65	Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	32.03	37.56	46.92	49.02	51.32	53.52	57.14	59.06	60.48	62.49	63.96	65.73	67.01
66	TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	32.03	37.56	46.92	49.02	51.32	53.52	57.14	59.06	60.48	62.49	63.96	65.73	67.01
68																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
75	GRA	-	-		-	-	-	0.71	0.71	0.71	0.71	0.71	0.71	4.60	4.59	4.59	4.59	4.59	4.58	4.58
76																				
77	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
78	Environmental Surcharge				0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
81	Net				(0.00)	0.16	0.53	0.89	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.99	41.49	50.83	52.91	55.18	57.35	61.38	63.28	64.68	66.66	68.13	69.89	71.15
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.99	41.49	50.83	52.91	55.18	57.35	61.38	63.28	64.68	66.66	68.13	69.89	71.15
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	27.92	27.90	27.96	27.97	27.99	27.97	31.10	31.12	31.13	31.10	31.16	31.17	31.18
89	TIER Adjustment	-	-		-	-	-	1.77	2.56	2.28	2.13	3.52	3.24	3.14	0.15	3.19	2.18	3.46	2.51	3.70
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	29.69	30.46	30.24	30.10	31.51	31.20	34.24	31.26	34.32	33.28	34.62	33.68	34.88
91	FAC				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
92	PPA	-	-		(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
93	Environmental Surcharge				0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
94	Surcharge 1	-	-		0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2				1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	42.54	51.60	53.31	54.57	58.49	59.62	65.41	62.92	67.83	68.18	71.41	71.80	74.98
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	50.22	56.65	60.91	62.50	65.48	65.49	67.86	70.00	74.05	75.37	74.97	79.93	80.37
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	41.40	49.00	53.27	54.79	58.05	59.38	64.23	63.60	67.06	68.04	70.43	71.53	73.84
102																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	93.6	112.2	139.5	147.8	157.4	166.7	182.4	191.6	199.8	209.9	218.7	228.5	237.0
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	35.3	43.8	56.3	60.5	65.1	69.7	76.5	81.1	85.1	90.0	94.4	99.3	103.5
108	Smelters	-	-	-	171.7	257.7	277.7	303.7	377.5	389.0	398.2	426.8	436.3	477.3	459.1	495.0	498.9	521.1	523.9	547.1
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	66.3	68.6	73.0	73.2	73.1	70.9	62.1	69.0	51.5	54.1	56.1	54.7	56.2
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	4.0	3.823	3.8	4.1	4.3	4.6	5.1	5.7	6.1	6.6	7.1	7.4
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	505.2	607.1	663.0	684.5	717.4	739.5	795.5	798.1	830.3	851.2	888.9	905.5	942.7
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	227.1	228.3	238.5	245.1	246.0	253.5	252.0	257.3	252.9	262.2	266.4	268.0	271.2
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	30.8	30.5	36.8	29.6	33.8	33.7	53.3	37.1	51.3	45.2	51.5	55.6	65.8
122	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Carbon Allowance Cost			-	-	-	-	-	92.6	104.6	119.7	133.2	146.8	155.3	174.4	182.0	199.6	214.5	226.5	241.3
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	*Property Taxes & Insurance*	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(6.9)	0.5	(1.7)	(2.2)	(1.5)	(1.8)	(0.4)	(2.2)	(1.5)	(2.6)	(1.3)	(2.6)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	436.1	528.1	569.8	582.1	615.1	635.5	684.7	681.1	714.8	734.5	772.7	792.0	828.8
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	79.0	93.2	102.4	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
136																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	*1.000*	*0.331*	*0.000*	*0.000*	*0.000*	*0.000*	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
137																				
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	79.0	93.2	102.4	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	*47.2*	*11.9*	*18.9*	*12.9*	*25.1*	*57.6*	*64.6*	*64.6*	*65.7*	*70.3*	*70.9*	*68.0*	*71.1*	*68.3*	*66.1*	*64.6*
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	*Post-Finance Cash Flow*	42.0	(3.5)	-	8.1	(46.5)	(39.5)	(45.5)	(33.3)	(0.8)	6.2	6.2	7.3	11.9	12.5	9.6	12.7	9.9	7.7	6.2
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	20.4	28.4	-	-	-	-	-	-	-	-	-	-	-
167	*Net Before Transition Reserve*			25.1	5.5	12.5	19.1	20.4	28.4	-	-	-	-	-	-	-	-	-	-	-
168																				
169 170	Ending Cash Balances (Incl. Transition Reserve)	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.3	88.5	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6	178.8

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
171	**IV. Income Statement (M$)**															Transaction Closing Date:			4/30/2008	
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.5	87.1	88.8	96.0	112.2	139.5	147.8	157.4	166.7	182.4	191.6	199.8	209.9	218.7	228.5	237.0
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	36.2	43.8	56.3	60.5	65.1	69.7	76.5	81.1	85.1	90.0	94.4	99.3	103.5
176	Smelters	-	-	-	170.6	254.9	275.0	310.4	377.5	389.0	398.2	426.8	436.3	477.3	459.1	495.0	498.9	521.1	523.9	547.1
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	66.3	68.6	73.0	73.2	73.1	70.9	62.1	69.0	51.5	54.1	56.1	54.7	56.2
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	*Gain on Sale of Allowances*	-	-	-	*14.3*	*18.5*	*(2.0)*	*0.7*	*0.4*	*0.8*	*0.4*	*(9.6)*	*(8.9)*	*(8.0)*	*(8.4)*	*(7.3)*	*(8.2)*	*(8.6)*	*(8.6)*	*(9.2)*
181	WKEC Lease (Net)	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	4.031	3.823	3.789	4.056	4.323	4.637	5.146	5.681	6.092	6.638	7.060	7.388
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	514.6	606.6	662.5	684.0	716.9	738.9	794.9	797.6	829.8	850.7	888.3	904.9	942.1
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	27.9	33.1	28.2	31.0	33.6	46.3	35.7	47.4	43.4	47.4	53.0	59.4
189	Carbon Tax				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
190	Carbon Allowance Cost				-	-	-	-	92.6	104.6	119.7	133.2	146.8	155.3	174.4	182.0	199.6	214.5	226.5	241.3
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
192	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	519.1	619.1	646.5	668.0	700.9	722.9	778.8	781.5	813.6	834.4	872.1	888.6	925.7
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	20.4	28.4	-	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
210																	Transaction Closing Date:		4/30/2008	
211	**V. Balance Sheet (M$)**																			
212																				
213	Assets																			
214	Property																			
215	Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216	Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217	Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218	Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219	Current																			
220	Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	53.4	46.8	44.1	48.5	52.7	58.0	67.7	78.0	85.3	95.6	102.9	107.9	111.3
222	Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223	Economic Reserve	-	-	75.0	71.6	62.1	45.7	27.3	-	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	42.5	50.2	54.9	56.7	59.4	61.2	65.9	66.0	68.7	70.4	73.5	74.8	77.9
225	Regulatory Asset	-	-	-	-	-	-	0.3	2.9	6.6	8.0	10.8	11.0	18.0	19.4	23.3	25.1	29.1	31.7	38.1
226	Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4
227	Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228	Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229	Credits																			
230	AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231	Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232	Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233	Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234	LEM Settlement Note/Marketing Paymer	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Total Assets	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,589.1	1,600.6	1,611.2	1,623.0	1,633.0	1,646.0	1,652.9	1,663.8	1,673.0	1,684.4	1,692.5	1,703.7
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	432.5	448.5	464.4	480.4	496.4	512.5	528.6	544.7	560.8	577.1	593.3	609.7	626.1
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241	Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242	Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243	Current & Accrued Liabilities																			
244	Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	63.1	77.6	81.6	84.8	89.5	92.7	98.9	99.2	103.9	106.9	112.4	114.8	120.2
245	Regulatory Liability				1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247	Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	27.3	-	-	-	-	-	-	-	-	-	-	-	-
248	Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249	Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250	Deferred TIER Rebate Payable				1.7	5.8	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
251	WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252	Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253	Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,589.1	1,600.6	1,611.2	1,623.0	1,633.0	1,646.0	1,652.9	1,663.8	1,673.0	1,684.4	1,692.5	1,703.7
255																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	2.9	7.8	4.7	1.8	2.7	1.8	4.6	0.2	2.6	1.7	3.1	1.3	3.1
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	(4.0)	(14.5)	(4.0)	(3.3)	(4.7)	(3.1)	(6.2)	(0.3)	(4.7)	(3.0)	(5.5)	(2.4)	(5.4)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(6.9)	0.5	(1.7)	(2.2)	(1.5)	(1.8)	(0.4)	(2.2)	(1.5)	(2.6)	(1.3)	(2.6)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.3	88.5	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6
272	Ending	138.4	134.9	160.0	173.6	139.7	119.3	94.2	89.3	88.5	94.8	101.0	108.3	120.2	132.7	142.3	155.1	165.0	172.6	178.8
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	Plus: Imputed Rate Increase in 2010				-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
282	Total				40.7	60.5	59.8	59.0	58.3	57.4	56.4	55.4	54.5	53.4	52.2	51.1	49.9	48.5	47.3	45.6
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
291																				
292	Conventional TIER																			
293	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	60.7	60.0	59.9	59.0	58.1	57.3	56.3	55.3	54.2	53.1	51.9	50.9	49.3
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	75.2	75.1	75.5	75.3	75.1	75.0	74.8	74.7	74.6	74.5	74.3	74.4	74.0
299	Divided by																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31
305																				

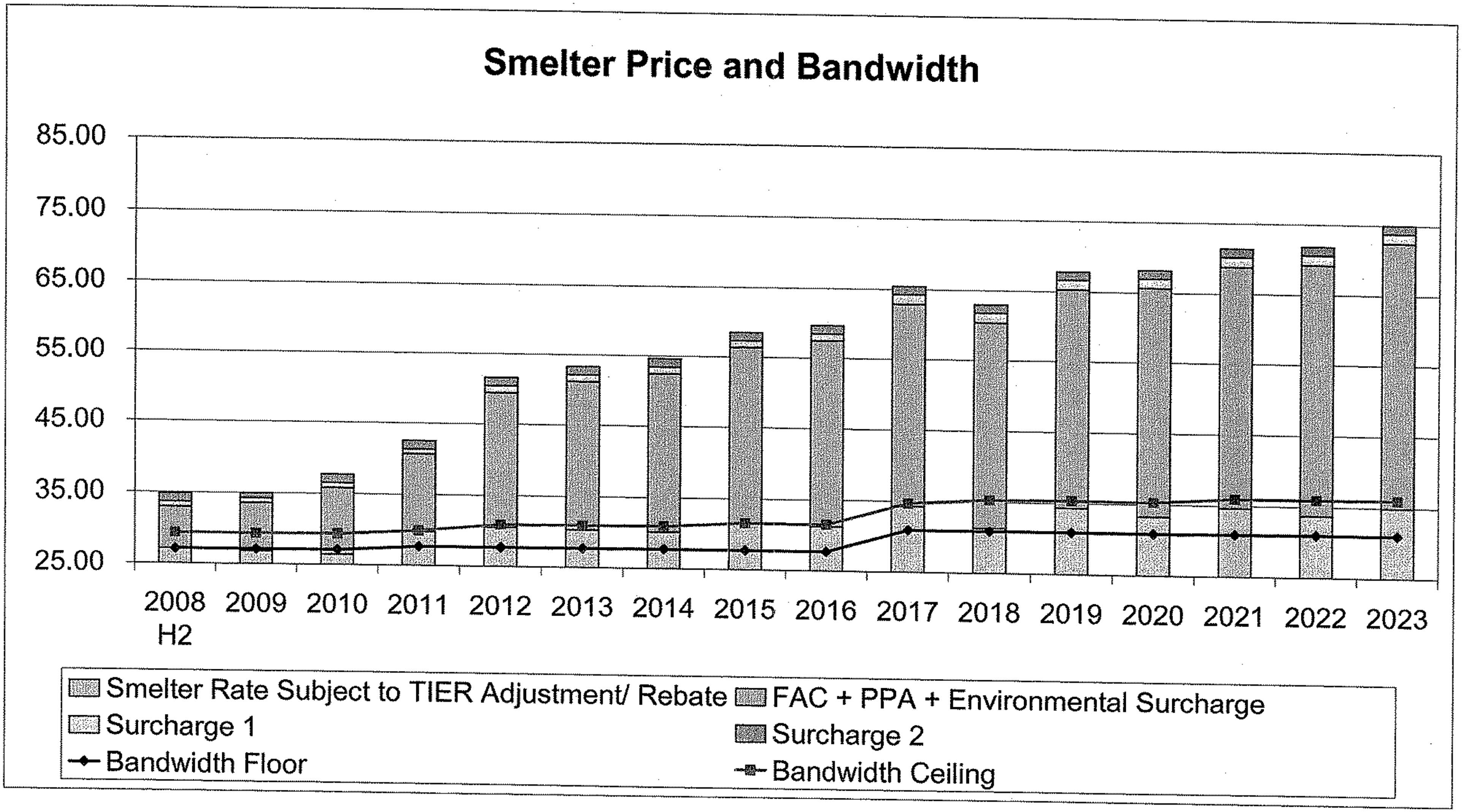
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
306	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
307	Cash Available for Debt Service																			
308	Receipts less Disbursements				84.6	88.0	77.5	69.2	79.0	93.2	102.4	102.3	103.9	110.7	117.0	115.6	116.8	116.2	113.5	113.9
309	Economic Reserve				5.5	12.5	19.1	20.4	28.4	-	-	-	-	-	-	-	-	-	-	-
310	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
311	Net				90.2	100.5	96.6	89.5	107.4	93.2	102.1	101.9	103.5	110.3	116.6	115.1	116.3	115.6	113.0	113.3
312	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
313	Total				99.1	113.8	110.5	104.0	122.5	108.8	118.4	119.0	121.3	128.9	136.0	135.5	137.6	138.0	136.5	138.0
314	Divided by																			
315	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
316	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
317	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
318	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
319																				
320	*DSCR*				2.06	1.59	1.53	1.43	1.67	1.47	1.58	1.58	1.59	1.67	1.75	1.72	1.73	1.71	1.67	1.66
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	106.7	91.8	88.9	91.6	97.9	104.7	114.3	126.5	137.5	148.7	160.0	168.8	175.7
324	Line of Credit				66.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
325	Total	117.5	136.7	147.5	233.8	256.6	229.5	206.7	191.8	188.9	191.6	197.9	204.7	214.3	226.5	237.5	248.7	260.0	268.8	275.7
326	Divided by																			
327	Total Operating Expense																			
328	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
330	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	27.9	33.1	28.2	31.0	33.6	46.3	35.7	47.4	43.4	47.4	53.0	59.4
331	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
332	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
333	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
334	APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
335	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
336	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
337	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
338	Total	182.8	69.2	-	293.6	439.0	450.9	477.3	483.2	497.9	504.2	522.0	528.8	562.1	544.2	567.5	569.3	590.6	593.5	614.4
339																				
340	*Days Cash on Hand (including Line o.*	234.5	721.0		290.6	213.4	185.8	158.1	144.8	138.5	138.7	138.4	141.3	139.2	151.9	152.8	159.5	160.7	165.3	163.8
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		207.4	130.2	104.8	81.6	69.3	65.2	66.4	68.4	72.2	74.2	84.8	88.5	95.3	98.9	103.8	104.4
342																				

	Calendar Year	2007	2008H1	Transac tion	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	Beginning Principal		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	859.1	851.2	839.0	826.0	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

December 2007

Smelter Rate Structure

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
3 Alcan	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
4 Total Energy (TWh)	4.898	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297
5 Total Demand (GW)	6.847	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.35	10.35	11.47	11.47	11.47	11.47	11.47	11.47	11.47
13 Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	13.99	13.99	15.50	15.50	15.50	15.50	15.50	15.50	15.50
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
17 Less: Regulatory Account Charge	-	-	-	-	-	(0.25)	(0.25)	(0.24)	(0.87)	(0.85)	(0.84)	(1.47)	(1.44)	(1.41)	(2.07)	(2.03)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	31.13	31.16	31.17	31.19	31.21	31.24	34.71	34.73	34.74	34.78	34.78	34.79	34.80
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.67	27.65	27.71	27.72	27.74	27.72	30.85	30.87	30.88	30.85	30.91	30.92	30.93
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.92	27.90	27.96	27.97	27.99	27.97	31.10	31.12	31.13	31.10	31.16	31.17	31.18
23 Plus TIER Adjustment	-	-	-	1.77	2.56	2.28	2.13	3.52	3.24	3.14	0.15	3.19	2.18	3.46	2.51	3.70
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	29.69	30.46	30.24	30.10	31.51	31.20	34.24	31.26	34.32	33.28	34.62	33.68	34.88
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	10.95	18.94	20.87	22.27	24.78	26.22	28.57	29.06	30.92	32.31	34.19	35.52	37.50
28 Plus Surcharge 1	0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
29 Plus Surcharge 2	1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	42.54	51.60	53.31	54.57	58.49	59.62	65.41	62.92	67.83	68.18	71.41	71.80	74.98
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	27.92	27.90	27.96	27.97	27.99	27.97	31.10	31.12	31.13	31.10	31.16	31.17	31.18
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	29.87	30.85	30.91	30.92	31.54	31.52	34.65	35.27	35.28	35.25	35.91	35.92	35.93
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	29.69	30.46	30.24	30.10	31.51	31.20	34.24	31.26	34.32	33.28	34.62	33.68	34.88



Smelter Price and Bandwidth

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	132.2	156.0	195.8	208.4	222.5	236.4	258.8	272.6	284.9	299.9	313.1	327.8	340.5
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	297.5	358.8	372.3	382.7	401.1	412.6	454.4	458.1	471.7	482.9	495.8	505.6	520.1
Other Revenues	75.8	115.1	102.9	92.4	101.5	77.7	77.4	67.6	66.3	58.8	65.8	49.9	51.9	54.1	53.2	54.5
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	522.1	616.3	645.8	668.4	691.2	715.2	772.0	796.5	806.5	834.7	863.1	886.6	915.1
Total Expenses	315.2	473.3	486.4	519.1	619.1	646.5	668.0	700.9	722.9	778.8	781.5	813.6	834.4	872.1	888.6	925.7
Net Margin Before TIER Adjustment	12.3	21.7	23.3	3.0	(2.8)	(0.7)	0.4	(9.7)	(7.6)	(6.9)	15.1	(7.1)	0.3	(9.0)	(2.0)	(10.6)
Interest + Margin	52.4	81.2	82.7	62.3	56.4	58.3	59.1	48.8	50.6	51.2	72.9	50.5	57.7	48.2	55.1	46.1
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	1.05	0.95	0.99	1.01	0.83	0.87	0.88	1.26	0.88	1.00	0.84	0.97	0.81
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	11.2	17.0	14.8	13.6	23.7	21.6	20.8	(1.2)	20.9	13.5	22.7	15.7	24.2
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
Less: Offset to Imputed Rate Increase in 2010	-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Total Adjustments	(1.0)	(1.5)	0.9	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	12.9	18.7	16.6	15.5	25.7	23.7	22.9	1.1	23.3	15.9	25.3	18.3	27.0
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	12.9	18.7	16.6	15.5	25.7	23.7	22.9	1.1	23.3	15.9	25.3	18.3	27.0
Rebate to Members/Smelters ($/MWh)																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	-	-	-	1.77	2.56	2.28	2.13	3.52	3.24	3.14	0.15	3.19	2.18	3.46	2.51	3.70

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.52	7.52	8.33	8.33	8.33	8.33	8.33	8.33	8.33
10	Energy ($/ MWH)	20.40	20.40	20.40	20.81	20.81	20.81	20.81	20.81	20.81	23.06	23.06	23.06	23.06	23.06	23.06	23.06
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
14	GRA	-	-	-	0.74	0.74	0.74	0.74	0.74	0.74	4.83	4.83	4.82	4.82	4.82	4.82	4.81
15	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
16	Env. Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
20	Net	(0.00)	(0.01)	(0.02)	(0.04)	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
21	Effective Rate	36.07	36.11	36.09	36.82	43.25	52.61	54.68	56.96	59.12	63.36	65.26	66.66	68.62	70.11	71.86	73.12
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.35	10.35	11.47	11.47	11.47	11.47	11.47	11.47	11.47
26	Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	13.99	13.99	15.50	15.50	15.50	15.50	15.50	15.50	15.50
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
30	GRA	-	-	-	0.63	0.63	0.63	0.63	0.63	0.63	4.10	4.10	4.10	4.10	4.10	4.10	4.10
31	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
32	Env. Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
36	Net	(0.00)	0.02	0.06	0.09	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
37	Effective Rate	30.58	30.48	30.54	31.22	37.56	46.92	49.02	51.32	53.52	57.14	59.06	60.48	62.49	63.96	65.73	67.01
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	0.25	0.25	0.24	0.87	0.85	0.84	1.47	1.44	1.41	2.07	2.03
43	GRA	-	-	-	0.71	0.71	0.71	0.71	0.71	0.71	4.60	4.59	4.59	4.59	4.59	4.58	4.58
44	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
45	Env. Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.56)	-	-	-	-	-	-	-	-	-	-	-
49	Net	(0.00)	0.00	0.00	0.00	6.40	15.50	17.58	19.87	21.40	21.57	23.49	24.26	26.27	27.78	28.87	30.18
50	Effective Rate	34.44	34.40	34.39	35.10	41.49	50.83	52.91	55.18	57.35	61.38	63.28	64.68	66.66	68.13	69.89	71.15
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	(6.67)	-	-	-	-	-	-	-	-	-	-	-	-

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	2.69	2.65	4.63	2.40	3.77	3.78	10.59	5.04	10.39	8.21	10.54	12.23	16.11
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	(2.69)	(2.65)	(4.63)	(2.40)	(3.77)	(3.78)	(10.59)	(5.04)	(10.39)	(8.21)	(10.54)	(12.23)	(16.11)
8	Total	1.26	(0.17)	1.33	(2.69)	(2.65)	(4.63)	(2.40)	(3.77)	(3.78)	(10.59)	(5.04)	(10.39)	(8.21)	(10.54)	(12.23)	(16.11)
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						0.97	0.97	0.97	3.60	3.60	3.60	6.47	6.47	6.47	9.71	9.71
12	Debit Power Purchase Expense						0.97	0.97	0.97	3.60	3.60	3.60	6.47	6.47	6.47	9.71	9.71
13																	
14	Net Income	(1.26)	0.17	(1.33)	2.69	2.65	4.63	2.40	3.77	3.78	10.59	5.04	10.39	8.21	10.54	12.23	16.11
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						0.97	1.94	2.91	6.51	10.11	13.71	20.18	26.65	33.12	42.83	52.55
19	Regulatory Asset	-	-	-	0.27	2.91	6.57	8.00	10.79	10.98	17.97	19.41	23.34	25.07	29.14	31.65	38.05
20	Total	-	-	-	0.27	2.91	7.54	9.94	13.71	17.49	28.07	33.12	43.51	51.72	62.26	74.48	90.60
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	0.3	2.9	7.5	9.9	13.7	17.5	28.1	33.1	43.5	51.7	62.3	74.5	90.6
24	Regulatory Liability	1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	0.3	2.9	7.5	9.9	13.7	17.5	28.1	33.1	43.5	51.7	62.3	74.5	90.6

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.6	11.7	11.6	11.9	11.9	12.0	11.6	12.0	11.6	11.9	11.9	11.9	11.9
2	**Sales (TWh)**	8.3	12.3	12.5	12.3	12.3	12.3	12.4	12.4	12.5	12.4	12.6	12.4	12.5	12.6	12.7	12.8
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold	16.62	16.56	17.77	18.31	18.53	19.03	19.71	19.72	20.13	20.17	20.47	20.35	20.83	21.02	21.10	21.16
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	30.53	30.17	36.47	29.28	33.43	33.42	52.97	36.80	50.97	44.82	51.13	55.23	65.43
13																	
14	Total Costs for Passthrough ($/ MWh Sold	1.21	1.80	1.38	2.48	2.45	2.95	2.36	2.69	2.67	4.26	2.92	4.11	3.58	4.04	4.36	5.12
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	32.19	128.12	140.22	157.13	184.71	199.03	206.51	228.37	234.63	255.36	273.03	285.45	302.90
20																	
21	Total Costs for Passthrough ($/ MWh Sold	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
29	Environmental Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
30	**Total**	6.39	6.69	9.73	10.22	18.24	19.67	21.66	23.85	25.30	26.06	27.89	28.56	30.48	31.90	32.91	34.14
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
33	Environmental Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
34	**Total**	6.39	6.69	9.73	10.22	18.24	19.67	21.66	23.85	25.30	26.06	27.89	28.56	30.48	31.90	32.91	34.14
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
37	PPA	(0.54)	0.05	(0.37)	0.73	0.70	1.20	0.61	0.93	0.92	2.51	1.17	2.36	1.82	2.29	2.61	3.37
38	Environmental Surcharge	0.49	0.85	2.68	2.62	10.43	11.36	12.66	14.84	15.90	16.62	18.14	18.93	20.38	21.60	22.53	23.70
39	**Total**	5.85	6.74	9.36	10.95	18.94	20.87	22.27	24.78	26.22	28.57	29.06	30.92	32.31	34.19	35.52	37.50

UW Transaction

		2007	2008H1	Transaction	2008 H2
	($M)		0		0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	**1. Cash Payment/ Credit Escrow Draws**	-	-	301.5	-
2	**2. WKE Residual Value Obligation**				
3	**WKE Gen. Capex - Cum.**				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	**3. LG&E Rental Income Advance**				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	**4. Fuel & Other Inventories**	-	-	55.0	-
20	**5. Cancellation of Settlement Prom. Note**	-	-	16.0	-
21	**6. Coleman Scrubber Completion**	-	-	97.5	-
22	**7. LG&E Emissions Allowance**	-	-	10.9	-
23	**8. Expense Unamortized Mktg Payment/ Settlement Note**			(15.7)	
24	**9. Assurances Agreement**	-	-	4.3	-
25					
26	**Total Residual Value Obligation**	154.1	161.8	161.8	-
27	**Cancellation of RV Obligation**				
28	Reclassification as Equity	-	-	161.8	-
29					
30	**Net WKE Obligation**	154.1	161.8	-	-
31					

UW Transaction

December 2007

($M)

			2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
32						
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction				134.9	
35	*Transaction Proceeds*				301.5	
36	Smelter Payment (Assurances Agreement)				(4.3)	
37	Consent Fee to Lease-Equity *Parties*				-	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				(0.3)	
41	Income Tax				(1.1)	
42	Net Transaction Cash				295.9	
43	Debt Restructuring:					
44	Debt Reduction (Net)				(186.2)	
45	Underwriting Costs	1.75%			(4.6)	
46	*Bond Insurance*	0.80%			(5.0)	
47	ARVP Defeasance Premium				-	
48	Total				(195.8)	
49	Restricted Cash Balances:					
50	Transition Reserve				(35.0)	
51	Economic Reserve				(75.0)	
52	Unrestricted Cash Balances Post-Transaction				125.0	
53						
54	**C. Debt Restructuring:**					
55	*Beginning Balance - GAAP*				1,051.1	
56	Cancellation of Settlement Prom. Note				(16.0)	
57	Capitalize Accrued Interest on RUS New Note				7.2	
58	Step-Up RUS New Note to Stated Basis:					
59	GAAP RUS New Note					
60	Ending Balance				791.4	
61	Accrued Interest				7.2	
62	Total				798.6	
63	Stated RUS New Note					
64	Ending Balance				794.7	
65	Accrued Interest				7.0	
66	*Total*				801.7	
67	Step-Up				3.1	
68	Beginning Balance - Stated				1,045.3	
69	Cash Flow:					
70	Prepay RUS New Note				(449.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				263.5	
73	Net				(186.2)	
74	Ending Balance - Stated				859.2	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.3)	
76	Ending Balance - GAAP				857.8	
77						

UW Transaction

			2007	2008H1	Transaction	2008 H2
	($M)			0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				
121						
122	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
123						
124	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
125						
126	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production-Fixed

Production - Fixed

	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

December 2007

67	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
68																					
69	Depreciation																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	Blended Depreciation Adj.		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

December 2007

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																			
2	Beginning Balance			-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest			-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service			(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																				
9	Fixed/ Insured (Tranche 2)																			
10	Beginning Balance			-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)			0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest			-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service			(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																				
17	RUS -- GAAP																			
18	Beginning Balance			791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon			0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)			0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest			-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest			440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service			440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																				
25	Variable																			
26	Beginning Balance			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon			0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																				
33	PCB																			
34	Beginning Balance			142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon			0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal			-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																				
41	ARVP																			
42	Beginning Balance			101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%		5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	Total																			
52	Beginning Balance			1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal			177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service			177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance			857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																				

Unwind Debt

December 2007

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
59	*Supporting Schedules*																			
60	Amortization of Financing Costs																			
61	Fixed/ Insured (Tranche 1)																			
62	Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63	BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64	YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65	Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67	EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71	BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72	YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73	Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74	Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75	EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																				
77	Variable																			
78	Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83	EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																				
85																				
86	Amortization of Financing Costs																			
87	Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88	Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89	Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																				
91	Interest Expense																			
92	Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93	ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94	Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95	AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96	Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97	Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

December 2007

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

December 2007

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	Defeasance Income	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	Additions	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	Non-Incremental	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476)	0	0
				185,791,428		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

	Electricity Sales, Purchases, and Production	Source:	005/ Othe	2006	2007	2008H1	Transactio 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Sales																						
2	*Rural*																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.936	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	366	366	366	366	366	366	366	366	366	366	366	366	366	366
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.16						2.789	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	*Smelter Retail Agreement, Section 1.1.14*						484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
18																							
19	Offsystem (TWh)	file: annual output - 12-15-07.xls		1.93	1.16	0.71		1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
20																							
21	Purchases & Production																						
22	Purchases (TWh)																						
23	Market	file: annual output - 12-15-07.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.46	0.38	0.54	0.37	0.42	0.42	0.72	0.47	0.66	0.53	0.55	0.62	0.71
24	SEPA	*Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls*		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 12-15-07.xls			-	-		8.07	11.80	12.10	11.63	11.71	11.65	11.88	11.87	11.95	11.56	11.97	11.58	11.66	11.94	11.90	11.92
26	Loss Rate (%)	file: annual output - 12-15-07.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	Fuel Consumption (MMBtu)	file: annual output - 12-15-07.xls						89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
29																							
30	Startup Costs (M$)	file: annual output - 12-15-07.xls			-	-		4.36	6.54	6.84	7.89	6.54	6.91	7.01	6.17	6.97	8.06	6.81	8.66	7.68	7.68	8.42	8.22
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		14,032	18,797	19,882	18,824	19,356	18,296	19,317	20,336	20,806	19,359	20,823	18,767	19,356	20,501	20,755	20,354
35	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	17,125	17,125	18,352	18,352	18,352
36	NOX																						
37	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		4,932	13,610	13,606	12,916	12,895	13,063	12,974	13,115	12,988	13,014	13,060	12,813	13,164	13,188	12,936	13,288
38	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		4,651	11,072	11,072	11,071	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 12-15-07.xls						1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 12-15-07.xls		67.8347	77.90	200.00		47.55	53.53	53.88	51.18	56.64	52.87	57.00	60.16	60.86	62.71	60.84	64.42	68.93	77.34	75.00	79.88
46	Variable Production ($/ *MWh sales*)	*file: annual output - 12-15-07.xls*			-	2.27		2.27	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
47	SO2 Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	778		778	853	881	818	792	747	*787*	*907*	*759*	*616*	*357*	*146*	*137*	*134*	*111*	*105*
48	NOX Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 12-15-07.xls	100%					4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
51																							
52	**Sales Rates & Related**																						
53																							
54	General Rate Adjustments (%)	*Stipulated Inputs (subject to Commission Approval at time)*						0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.00%	0.00%	10.83%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	Market ($/ MWh)	file: annual output - 12-15-07.xls		43.30	42.91	37.82		48.40	51.34	49.47	50.22	56.65	60.91	62.50	65.48	65.49	67.86	70.00	74.05	75.37	74.97	79.93	80.37
57																							
58	Rural																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	Smelters																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	*Annual Revenue Guarantee ($/ MWh)*	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	1.77	2.56	2.28	2.13	3.52	3.24	3.14	0.15	3.19	2.18	3.46	2.51	3.70
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	5.11	*7.30*	*7.30*	*7.30*	*7.30*	*7.30*	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																							
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback transaction		3.68	3.66000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	*Big Rivers Assumption*		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	-	-	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	(0.00)	(0.00)	-	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	10.72																				
83	*W/ Purchased Power (Total Sales Denom.)*	*Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0*	12.47																				
84	Allocation of Revenues on '																						
85	Total																						
86	NOx + SO3	file: annual output - 12-15-07.xls																					
87	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
89	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
91	Net Allowances	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
92	Total	file: annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
93	**Allowed In ES**																						
94	NOx + SO3	file: annual output - 12-15-07.xls																					
95	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
97	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
99	Net Allowance Costs in Excess of 2009	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
100	Total	file: annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Lev				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	*Prepayment on Transaction Date*	Modeled to achieve target cash balances		-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.15																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.65	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.19	11.41	12.77	-	25.85															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

Inputs

December 2007

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	Net Confomring Receipts	Big Rivers' estimate		-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	68.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.60	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (Includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Adjustment (8/2007)			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 8-29-07_Rev1.xls						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	Property Tax			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Cimn FGD Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	Phase I	Per Crockett Memo dated 11/12/07		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-			3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	Other Disbursements (M$)																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-																	
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	-
307	Green River Coal Settlement	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	*Payment to City of Henderson*	*file: annual output - 12-15-07.xls*		-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	- -	-	75.00	(5.54)	(12.52)	(19.11)	(20.39)	(28.43)	-	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.28%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,760.4	1,780.2																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	826.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	Historic Balance Sheet	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	Credit Escrow	Economic Reserve	-	-	-	-	75.0	71.6	62.1	45.7	27.3	-	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.6	0.8																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	Long-Term Debt																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(49.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	27.3	-	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	1.2	-	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(20.4)	(28.4)	-	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	27.3	-	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 12-16-07.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	**Depreciation**																						

Inputs

December 2007

		Source:	005/ Oths	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	*Additional Book Depreciation*																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic		6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Envitonmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		25.36	25.39	8.58		26.58	9.01														
475	*HMP&L Station Two*	Historic		1.58	1.64	0.54		0.93	0.31														
476	Other	Historic		5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation																						
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3 10	0																				
480	**Income Tax Related**							0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.80	0.00	0.00																	
490	Temporary Differences																						
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	5.58	5.70																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																				
513																							
514	*Carbon Tax Cost ($/MWh)*	*$7/ton charge starting in 2012, escalating $1/year*						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	7.91	8.98	10.07	11.22	12.29	13.44	14.57	15.71	16.83	17.97	19.04	20.24
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Fuel Inventory

December 2007

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,100	10,999	11,019	11,045	11,021	11,060	11,069	11,037	11,015	11,028	11,021	11,037	11,003
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.20	22.00	22.04	22.09	22.04	22.12	22.14	22.07	22.03	22.06	22.04	22.07	22.01
7	Coal Consumed [from PCM (000s tons)]		4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(129,052)	(129,383)	(128,057)	(130,536)	(130,460)	(131,239)	(127,332)	(131,626)	(127,278)	(130,423)	(131,329)	(130,729)	(131,111)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6
19	Fuel Purchased	-	133.3	197.7	220.4	219.2	221.7	231.6	238.1	239.8	246.5	244.0	250.5	244.3	254.5	258.8	259.6	263.0
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(217.2)	(221.2)	(228.1)	(237.6)	(239.3)	(245.0)	(242.6)	(250.9)	(243.7)	(253.3)	(258.1)	(259.0)	(262.3)
22	EB	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4

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December 2007

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
1	**I. Sales (TWH)**																			
2																				
3	Rural																			
4		2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
5	Large Industrial																			
6		0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
7	Century																			
8		-	-	-	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
9	Alcan																			
10		-	-	-	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
11	Market																			
12		1.16	0.71	-	1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
13	Total Sales																			
14		4.53	1.80	-	8.28	12.29	12.49	12.29	12.29	12.35	12.41	12.45	12.52	12.43	12.59	12.40	12.53	12.64	12.67	12.78

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																Transaction Closing Date:		4/30/2008	
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.98%	0.00%	9.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FAC ($/ MWH)				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
PPA ($/ MWH)				(0.54)	0.05	(0.37)	0.73	0.49	0.86	0.35	0.61	0.57	1.83	0.71	1.62	1.21	1.62	1.80	2.41
Environmental Surcharge Adjustment ($/ MWH)																			
Rural				0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
Large Industrial				0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
Smelters				0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
Rural																			
Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.59	7.59	8.35	8.35	8.35	8.35	8.35	8.35	8.35
Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.81	20.81	20.81	20.81	21.01	21.01	23.11	23.11	23.11	23.11	23.11	23.11	23.11
Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
Regulatory Account Charge				-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
GRA	-	-		-	-	-	0.74	0.74	0.74	0.74	1.11	1.11	4.92	4.92	4.91	4.91	4.91	4.91	4.90
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.16	0.53	0.89	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.75	36.85	45.04	46.33	48.09	49.16	52.14	53.28	53.38	54.58	55.29	55.99	56.50
TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.75	36.85	45.04	46.33	48.09	49.16	52.14	53.28	53.38	54.58	55.29	55.99	56.50
Large Industrial																			
Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.45	10.45	11.50	11.50	11.50	11.50	11.50	11.50	11.50
Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
Regulatory Account Charge				-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
GRA	-	-		-	-	-	0.63	0.63	0.63	0.63	0.94	0.94	4.17	4.17	4.17	4.17	4.17	4.17	4.17
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.16	0.53	0.89	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	32.03	31.16	39.36	40.67	42.39	43.51	45.90	47.06	47.18	48.43	49.13	49.85	50.38
TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	32.03	31.16	39.36	40.67	42.39	43.51	45.90	47.06	47.18	48.43	49.13	49.85	50.38

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
69	Non-Smelter Member Blend																Transaction Closing Date:		4/30/2008	
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
75	GRA	-	-		-	-	-	0.71	0.71	0.71	0.71	1.06	1.06	4.68	4.68	4.68	4.68	4.67	4.67	4.67
76																				
77	FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
78	Environmental Surcharge				0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
81	Net				(0.00)	0.16	0.53	0.89	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.99	35.09	43.27	44.56	46.30	47.38	50.16	51.30	51.40	52.61	53.31	54.01	54.53
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.99	35.09	43.27	44.56	46.30	47.38	50.16	51.30	51.40	52.61	53.31	54.01	54.53
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.27	28.25	31.17	31.18	31.20	31.17	31.23	31.24	31.25
89	TIER Adjustment	-	-		-	-	-	1.77	2.63	2.38	2.24	3.16	2.88	3.14	0.15	3.17	2.16	3.45	2.50	3.69
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	29.69	30.53	30.34	30.21	31.43	31.12	34.31	31.34	34.37	33.33	34.68	33.74	34.94
91	FAC				5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
92	PPA	-	-		(0.54)	0.05	(0.37)	0.73	0.49	0.86	0.35	0.61	0.57	1.83	0.71	1.62	1.21	1.62	1.80	2.41
93	Environmental Surcharge				0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
94	Surcharge 1	-	-		0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
95	Surcharge 2				1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	42.54	44.96	45.67	46.14	48.91	49.16	53.77	50.74	54.26	53.96	56.35	55.74	58.01
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	50.22	49.48	52.67	53.42	55.37	54.46	55.41	56.98	59.56	60.21	58.91	62.81	62.27
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	41.40	42.38	45.60	46.32	48.64	49.03	52.67	51.42	53.54	53.83	55.40	55.48	56.94
102																				

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December 2007

	Calend	2007	2008H1	Transac tion	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	93.6	95.6	119.4	125.3	132.9	138.6	150.1	156.4	160.0	166.9	172.5	178.1	183.2
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	35.3	36.3	47.2	50.2	53.8	56.7	61.4	64.6	66.4	69.7	72.5	75.3	77.8
108	Smelters	-	-	-	171.7	257.7	277.7	303.7	329.0	333.3	336.7	356.9	359.7	392.4	370.3	395.9	394.8	411.2	406.7	423.3
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	66.3	59.9	63.2	62.6	61.8	58.9	50.7	56.2	41.4	43.2	44.1	43.0	43.6
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	4.0	3.638	3.6	3.9	4.2	4.5	5.0	5.5	6.0	6.5	6.9	7.3
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	505.2	525.8	568.1	579.3	600.3	609.7	651.6	644.6	662.5	672.9	698.7	702.0	726.5
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	227.1	228.3	238.5	245.1	246.0	253.5	252.0	257.3	252.9	262.2	266.4	268.0	271.2
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	30.8	27.9	32.5	26.4	29.7	29.3	44.8	31.3	42.2	37.5	43.0	45.4	53.5
122	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Carbon Allowance Cost			-	-	-	-	-	12.7	13.3	16.9	19.0	21.3	18.3	26.0	22.2	28.3	31.8	32.5	35.8
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(1.8)	1.2	(1.0)	(1.4)	(0.7)	(0.9)	0.2	(1.4)	(0.9)	(1.9)	(0.4)	(1.8)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	436.1	450.7	475.0	476.8	497.6	506.3	540.1	527.4	546.7	556.2	582.4	588.6	611.8
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	75.0	93.1	102.5	102.6	103.4	111.5	117.2	115.8	116.7	116.4	113.4	114.7
136																				

Transaction Closing Date: 4/30/2008

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
137																				
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	69.2	75.0	93.1	102.5	102.6	103.4	111.5	117.2	115.8	116.7	116.4	113.4	114.7
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	47.2	11.9	18.9	12.9	21.2	57.5	64.7	65.0	65.2	71.1	71.1	68.3	71.1	68.5	66.0	65.4
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	Post-Finance Cash Flow	42.0	(3.5)	-	8.1	(46.5)	(39.5)	(45.5)	(37.2)	(0.9)	6.3	6.6	6.8	12.7	12.7	9.9	12.7	10.1	7.6	7.0
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	20.4	28.0	0.4	-	-	-	-	-	-	-	-	-	-
167	Net Before Transition Reserve			25.1	5.5	12.5	19.1	20.4	28.0	0.4	-	-	-	-	-	-	-	-	-	-
168																				
169	Ending Cash Balances (Incl. Transition	138.4	134.9	160.0	173.6	139.7	119.3	94.2	85.0	84.5	90.8	97.3	104.1	116.8	129.5	139.3	152.0	162.1	169.7	176.7
170	Reserve)																			

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
171	**IV. Income Statement (M$)**															Transaction Closing Date:			4/30/2008	
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.5	87.1	88.8	96.0	95.6	119.4	125.3	132.9	138.6	150.1	156.4	160.0	166.9	172.5	178.1	183.2
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	36.2	36.3	47.2	50.2	53.8	56.7	61.4	64.6	66.4	69.7	72.5	75.3	77.8
176	Smelters	-	-	-	170.6	254.9	275.0	310.4	329.0	333.3	336.7	356.9	359.7	392.4	370.3	395.9	394.8	411.2	406.7	423.3
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	66.3	59.9	63.2	62.6	61.8	58.9	50.7	56.2	41.4	43.2	44.1	43.0	43.6
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	0.7	0.4	0.8	0.4	(9.6)	(8.9)	(8.0)	(8.4)	(7.3)	(8.2)	(8.6)	(8.6)	(9.2)
181	WKEC Lease (Net)	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	4.031	3.638	3.617	3.886	4.166	4.456	4.999	5.541	5.963	6.507	6.939	7.263
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	514.6	525.3	567.5	578.8	599.7	609.2	651.1	644.1	662.0	672.4	698.2	701.4	725.9
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	26.0	29.9	25.7	27.9	29.4	39.5	30.6	39.4	36.4	39.9	43.6	48.7
189	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
190	Carbon Allowance Cost			-	-	-	-	-	12.7	13.3	16.9	19.0	21.3	18.3	26.0	22.2	28.3	31.8	32.5	35.8
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
192	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	519.1	537.4	552.0	562.8	583.7	593.1	635.0	628.0	645.8	656.2	681.9	685.1	709.6
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	20.4	28.0	0.4	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4

	Calendar Year	2007	2008H1	Transac tion	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
210																	Transaction Closing Date:		4/30/2008	
211	**V. Balance Sheet (M$)**																			
212																				
213	Assets																			
214	Property																			
215	Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216	Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217	Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218	Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219	Current																			
220	Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	53.4	42.4	40.1	44.5	49.1	53.8	64.3	74.7	82.2	92.5	100.1	105.0	109.2
222	Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223	Economic Reserve	-	-	75.0	71.6	62.1	45.7	27.3	0.4	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	42.5	43.4	47.0	47.9	49.7	50.4	53.9	53.3	54.7	55.5	57.6	57.9	59.9
225	Regulatory Asset	-	-	-	-	-	-	0.3	2.1	4.7	5.4	7.1	7.1	12.4	13.1	15.9	17.0	20.1	21.8	26.7
226	Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4
227	Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228	Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229	Credits																			
230	AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231	Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232	Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233	Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234	*LEM Settlement Note/Marketing Paymer*	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Total Assets	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,577.6	1,586.9	1,595.9	1,605.9	1,614.1	1,625.0	1,630.5	1,639.4	1,647.0	1,656.6	1,662.9	1,672.1
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	432.5	448.5	464.4	480.4	496.4	512.5	528.6	544.7	560.8	577.1	593.3	609.7	626.1
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241	Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242	Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243	Current & Accrued Liabilities																			
244	Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	63.1	65.6	67.8	69.5	72.5	73.7	77.9	76.9	79.4	80.9	84.7	85.1	88.7
245	Regulatory Liability				1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
246	Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247	Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	27.3	0.4	-	-	-	-	-	-	-	-	-	-	-
248	Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249	Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250	Deferred TIER Rebate Payable				1.7	5.8	9.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
251	WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252	Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253	Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,594.2	1,577.6	1,586.9	1,595.9	1,605.9	1,614.1	1,625.0	1,630.5	1,639.4	1,647.0	1,656.6	1,662.9	1,672.1
255																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	2.9	1.0	3.6	0.9	1.7	0.8	3.5	(0.6)	1.4	0.8	2.1	0.2	2.0
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	(4.0)	(2.6)	(2.2)	(1.7)	(3.0)	(1.3)	(4.2)	1.1	(2.6)	(1.5)	(3.7)	(0.4)	(3.6)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	(1.2)	(1.8)	1.2	(1.0)	(1.4)	(0.7)	(0.9)	0.2	(1.4)	(0.9)	(1.9)	(0.4)	(1.8)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	94.2	85.0	84.5	90.8	97.3	104.1	116.8	129.5	139.3	152.0	162.1	169.7
272	Ending	138.4	134.9	160.0	173.6	139.7	119.3	94.2	85.0	84.5	90.8	97.3	104.1	116.8	129.5	139.3	152.0	162.1	169.7	176.7
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	Plus: Imputed Rate Increase in 2010				-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
282	Total				40.7	60.5	59.8	59.0	58.3	57.4	56.4	55.4	54.5	53.4	52.2	51.1	49.9	48.5	47.3	45.6
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	73.5	73.4	73.1	72.7	72.5	72.3	71.9	71.7	71.4	71.2	70.9	70.8	70.3
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24	1.24
291																				
292	Conventional TIER																			
293	Earnings				10.6	15.8	13.3	15.9	15.9	16.0	16.0	16.0	16.1	16.1	16.1	16.2	16.2	16.3	16.4	16.4
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	60.7	60.0	59.9	59.0	58.1	57.3	56.3	55.3	54.2	53.1	51.9	50.9	49.3
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	75.2	75.1	75.5	75.3	75.1	75.0	74.8	74.7	74.6	74.5	74.3	74.4	74.0
299	Divided by																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	1.27	1.27	1.28	1.28	1.29	1.29	1.29	1.29	1.29	1.30	1.30	1.30	1.31
305																				

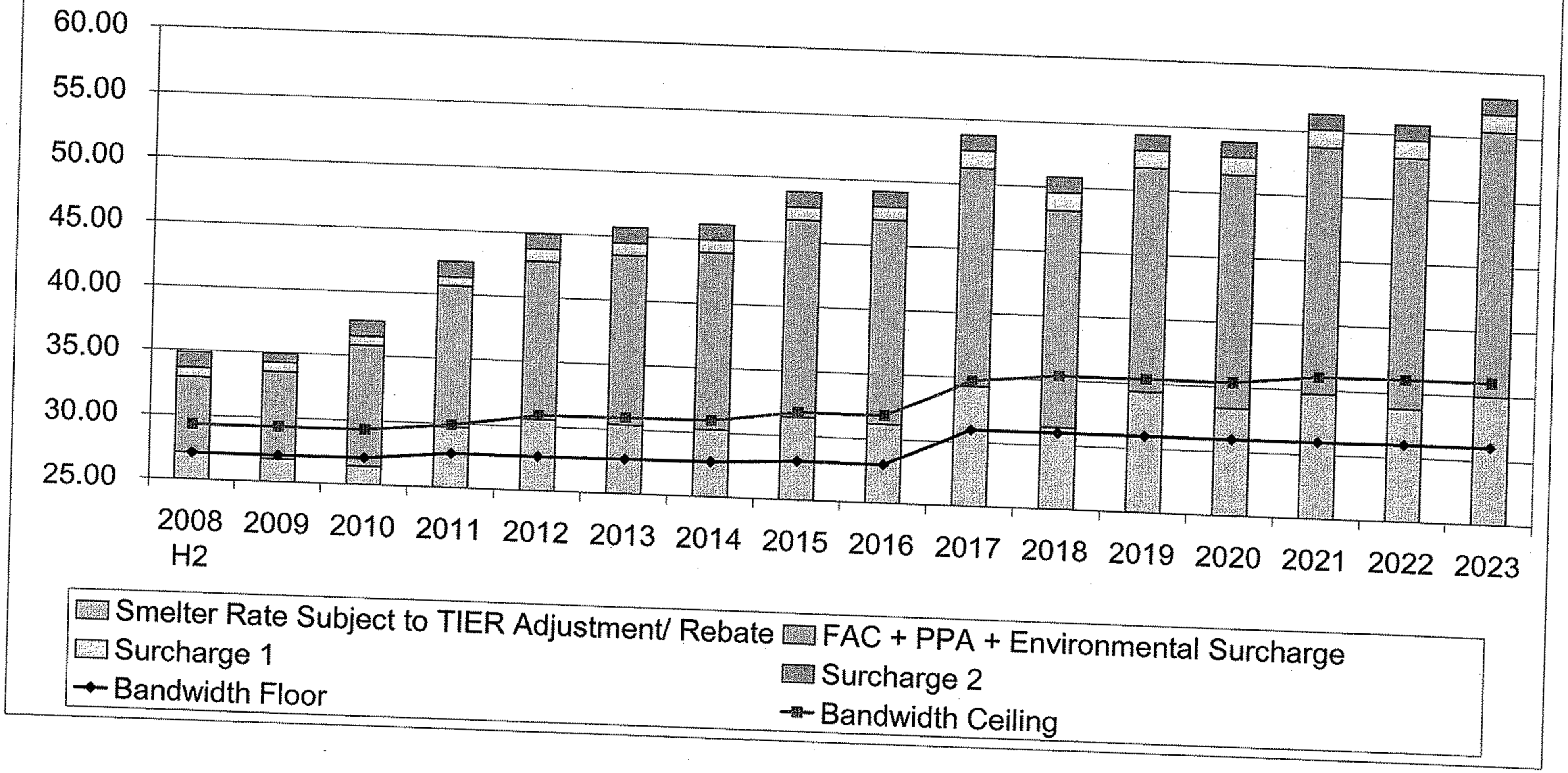
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	*1.000*	*0.331*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*	*0.000*
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
306	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
307	Cash Available for Debt Service																			
308	Receipts less Disbursements				84.6	88.0	77.5	69.2	75.0	93.1	102.5	102.6	103.4	111.5	117.2	115.8	116.7	116.4	113.4	114.7
309	Economic Reserve				5.5	12.5	19.1	20.4	28.0	0.4	-	-	-	-	-	-	-	-	-	-
310	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
311	*Net*				*90.2*	*100.5*	*96.6*	*89.5*	*103.1*	*93.5*	*102.1*	*102.3*	*103.0*	*111.1*	*116.8*	*115.3*	*116.2*	*115.9*	*112.9*	*114.1*
312	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
313	Total				99.1	113.8	110.5	104.0	118.1	109.1	118.5	119.3	120.7	129.7	136.2	135.7	137.6	138.2	136.4	138.8
314	Divided by																			
315	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
316	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
317	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
318	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
319																				
320	*DSCR*				2.06	1.59	1.53	1.43	1.61	1.47	1.59	1.58	1.58	1.68	1.75	1.72	1.73	1.71	1.67	1.67
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	106.7	89.6	84.7	87.7	94.1	100.7	110.5	123.1	134.4	145.7	157.1	165.9	173.2
324	Line of Credit				66.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
325	Total	117.5	136.7	147.5	233.8	256.6	229.5	206.7	189.6	184.7	187.7	194.1	200.7	210.5	223.1	234.4	245.7	257.1	265.9	273.2
326	Divided by																			
327	Total Operating Expense																			
328	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Fuel Costs	-	-	-	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
330	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	28.1	26.0	29.9	25.7	27.9	29.4	39.5	30.6	39.4	36.4	39.9	43.6	48.7
331	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.9	35.9	36.4	37.9	41.9	43.3	43.2	45.6	45.4	47.6	49.9	50.3	52.4
332	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
333	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
334	APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
335	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
336	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
337	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
338	Total	182.8	69.2	-	293.6	439.0	450.9	477.3	481.4	494.7	501.7	519.0	524.6	555.2	539.2	559.5	562.3	583.1	584.1	603.8
339																				
340	*Days Cash on Hand (including Line o.*	234.5	721.0		290.6	213.4	185.8	158.1	143.7	136.3	136.5	136.5	139.7	138.4	151.0	152.9	159.5	160.9	166.2	165.2
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		207.4	130.2	104.8	81.6	67.9	62.5	63.8	66.2	70.1	72.6	83.4	87.7	94.6	98.3	103.7	104.7
342																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	*Interest*		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	*Debt Service*		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	*Beginning Principal*		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	859.1	851.2	839.0	826.0	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

Smelter Rate Structure

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.98%	0.00%	9.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16	4.17	4.16	4.16	4.16
3 Alcan	2.11	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14	3.15	3.14	3.14	3.14
4 Total Energy (TWh)	4.898	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297	7.317	7.297	7.297	7.297
5 Total Demand (GW)	6.847	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200	10.200
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.45	10.45	11.50	11.50	11.50	11.50	11.50	11.50	11.50
13 Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
17 Less: Regulatory Account Charge	-	-	-	-	-	(0.18)	(0.18)	(0.18)	(0.58)	(0.56)	(0.55)	(0.99)	(0.97)	(0.95)	(1.43)	(1.40)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	31.13	31.16	31.17	31.19	31.52	31.56	34.79	34.80	34.82	34.86	34.85	34.87	34.88
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.67	27.65	27.71	27.72	28.02	28.00	30.92	30.93	30.95	30.92	30.98	30.99	31.00
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.27	28.25	31.17	31.18	31.20	31.17	31.23	31.24	31.25
23 Plus TIER Adjustment	-	-	-	1.77	2.63	2.38	2.24	3.16	2.88	3.14	0.15	3.17	2.16	3.45	2.50	3.69
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	29.69	30.53	30.34	30.21	31.43	31.12	34.31	31.34	34.37	33.33	34.68	33.74	34.94
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	10.95	12.23	13.13	13.72	15.28	15.84	16.87	16.81	17.29	18.03	19.08	19.40	20.47
28 Plus Surcharge 1	0.70	0.70	0.70	0.70	1.00	1.00	1.00	1.00	1.00	1.40	1.40	1.40	1.39	1.40	1.40	1.40
29 Plus Surcharge 2	1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	42.54	44.96	45.67	46.14	48.91	49.16	53.77	50.74	54.26	53.96	56.35	55.74	58.01
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	27.92	27.90	27.96	27.97	28.27	28.25	31.17	31.18	31.20	31.17	31.23	31.24	31.25
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	29.87	30.85	30.91	30.92	31.82	31.80	34.72	35.33	35.35	35.32	35.98	35.99	36.00
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	29.69	30.53	30.34	30.21	31.43	31.12	34.31	31.34	34.37	33.33	34.68	33.74	34.94

Smelter Price and Bandwidth



TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	132.2	131.9	166.7	175.5	186.7	195.3	211.5	221.0	226.4	236.7	245.0	253.4	261.0
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	297.5	309.7	315.9	320.3	333.9	338.7	369.5	369.2	372.8	379.0	386.0	388.5	396.3
Other Revenues	75.8	115.1	102.9	92.4	92.4	68.0	66.6	56.1	54.2	47.2	52.8	39.7	40.9	42.0	41.4	41.7
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	522.1	534.1	550.5	562.4	576.7	588.1	628.2	643.0	638.9	656.6	673.0	683.2	699.0
Total Expenses	315.2	473.3	486.4	519.1	537.4	552.0	562.8	583.7	593.1	635.0	628.0	645.8	656.2	681.9	685.1	709.6
Net Margin Before TIER Adjustment	12.3	21.7	23.3	3.0	(3.3)	(1.4)	(0.4)	(7.1)	(5.0)	(6.9)	15.0	(7.0)	0.4	(8.9)	(1.9)	(10.6)
Interest + Margin	52.4	81.2	82.7	62.3	55.9	57.5	58.3	51.4	53.3	51.2	72.8	50.6	57.8	48.2	55.2	46.1
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	1.05	0.94	0.98	0.99	0.88	0.91	0.88	1.26	0.88	1.01	0.84	0.97	0.81
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	11.2	17.5	15.6	14.4	21.1	19.0	20.8	(1.1)	20.8	13.4	22.7	15.6	24.2
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	2.6	2.7	2.7	2.8	2.8	2.9	3.0	3.0	3.1	3.2	3.2	3.3	3.4
Less: Offset to Imputed Rate Increase in 2010	-	-	-	(2.6)	(2.7)	(2.7)	(2.8)	(2.8)	(2.9)	(3.0)	(3.0)	(3.1)	(3.2)	(3.2)	(3.3)	(3.4)
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Total Adjustments	(1.0)	(1.5)	0.9	(1.7)	(1.7)	(1.8)	(1.9)	(2.0)	(2.1)	(2.2)	(2.2)	(2.3)	(2.4)	(2.5)	(2.7)	(2.8)
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	12.9	19.2	17.4	16.3	23.1	21.1	22.9	1.1	23.1	15.8	25.2	18.3	26.9
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	12.9	19.2	17.4	16.3	23.1	21.1	22.9	1.1	23.1	15.8	25.2	18.3	26.9
Rebate to Members/Smelters ($/MWh)																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	-	-	-	1.77	2.63	2.38	2.24	3.16	2.88	3.14	0.15	3.17	2.16	3.45	2.50	3.69

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.52	7.52	7.52	7.52	7.59	7.59	8.35	8.35	8.35	8.35	8.35	8.35	8.35
10	Energy ($/ MWH)	20.40	20.40	20.40	20.81	20.81	20.81	20.81	21.01	21.01	23.11	23.11	23.11	23.11	23.11	23.11	23.11
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
14	GRA	-	-	-	0.74	0.74	0.74	0.74	1.11	1.11	4.92	4.92	4.91	4.91	4.91	4.91	4.90
15	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
16	Env. Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
20	Net	(0.00)	(0.01)	(0.02)	(0.04)	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
21	Effective Rate	36.07	36.11	36.09	36.82	36.85	45.04	46.33	48.09	49.16	52.14	53.28	53.38	54.58	55.29	55.99	56.50
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.35	10.35	10.35	10.35	10.45	10.45	11.50	11.50	11.50	11.50	11.50	11.50	11.50
26	Energy ($/ MWH)	13.72	13.72	13.72	13.99	13.99	13.99	13.99	14.13	14.13	15.54	15.54	15.54	15.54	15.54	15.54	15.54
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
30	GRA	-	-	-	0.63	0.63	0.63	0.63	0.94	0.94	4.17	4.17	4.17	4.17	4.17	4.17	4.17
31	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
32	Env. Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
36	Net	(0.00)	0.02	0.06	0.09	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
37	Effective Rate	30.58	30.48	30.54	31.22	31.16	39.36	40.67	42.39	43.51	45.90	47.06	47.18	48.43	49.13	49.85	50.38
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	0.18	0.18	0.18	0.58	0.56	0.55	0.99	0.97	0.95	1.43	1.40
43	GRA	-	-	-	0.71	0.71	0.71	0.71	1.06	1.06	4.68	4.68	4.68	4.68	4.67	4.67	4.67
44	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
45	Env. Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(5.55)	(7.46)	(0.10)	-	-	-	-	-	-	-	-	-	-
49	Net	(0.00)	0.00	0.00	0.00	-	8.00	9.30	10.69	11.37	10.55	11.71	11.37	12.60	13.33	13.56	14.11
50	Effective Rate	34.44	34.40	34.39	35.10	35.09	43.27	44.56	46.30	47.38	50.16	51.30	51.40	52.61	53.31	54.01	54.53
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	(6.67)	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	2.69	1.85	3.30	1.37	2.45	2.33	7.70	3.05	7.15	5.46	7.46	8.46	11.52
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	(2.69)	(1.85)	(3.30)	(1.37)	(2.45)	(2.33)	(7.70)	(3.05)	(7.15)	(5.46)	(7.46)	(8.46)	(11.52)
8	Total	1.26	(0.17)	1.33	(2.69)	(1.85)	(3.30)	(1.37)	(2.45)	(2.33)	(7.70)	(3.05)	(7.15)	(5.46)	(7.46)	(8.46)	(11.52)
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						0.71	0.71	0.71	2.37	2.37	2.37	4.36	4.36	4.36	6.69	6.69
12	Debit Power Purchase Expense						0.71	0.71	0.71	2.37	2.37	2.37	4.36	4.36	4.36	6.69	6.69
13																	
14	Net Income	(1.26)	0.17	(1.33)	2.69	1.85	3.30	1.37	2.45	2.33	7.70	3.05	7.15	5.46	7.46	8.46	11.52
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						0.71	1.41	2.12	4.49	6.86	9.23	13.59	17.95	22.31	29.00	35.69
19	Regulatory Asset	-	-	-	0.27	2.12	4.71	5.37	7.12	7.08	12.41	13.08	15.87	16.97	20.07	21.84	26.67
20	Total	-	-	-	0.27	2.12	5.42	6.79	9.23	11.57	19.27	22.31	29.46	34.92	42.39	50.84	62.36
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	0.3	2.1	5.4	6.8	9.2	11.6	19.3	22.3	29.5	34.9	42.4	50.8	62.4
24	Regulatory Liability	1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	0.3	2.1	5.4	6.8	9.2	11.6	19.3	22.3	29.5	34.9	42.4	50.8	62.4

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.6	11.7	11.6	11.9	11.9	12.0	11.6	12.0	11.6	11.9	11.9	11.9	11.9
2	**Sales (TWh)**	8.3	12.3	12.5	12.3	12.3	12.3	12.4	12.4	12.5	12.4	12.6	12.4	12.5	12.6	12.7	12.8
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	225.1	227.7	235.0	244.6	245.5	252.0	250.6	257.8	252.3	261.0	265.7	267.4	270.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold	16.62	16.56	17.77	18.31	18.53	19.03	19.71	19.72	20.13	20.17	20.47	20.35	20.83	21.02	21.10	21.16
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	30.53	27.57	32.21	26.04	29.35	29.02	44.47	30.95	41.84	37.17	42.67	45.04	53.16
13																	
14	Total Costs for Passthrough ($/ MWh Sold	1.21	1.80	1.38	2.48	2.24	2.61	2.10	2.36	2.32	3.58	2.46	3.37	2.97	3.38	3.55	4.16
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	0.73	0.49	0.86	0.35	0.61	0.57	1.83	0.71	1.62	1.21	1.62	1.80	2.41
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	32.19	48.21	48.89	54.38	70.55	73.45	69.52	79.96	74.80	84.12	90.37	91.38	97.42
20																	
21	Total Costs for Passthrough ($/ MWh Sold	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
29	Environmental Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
30	**Total**	6.39	6.69	9.73	10.22	11.74	12.27	13.38	14.68	15.27	15.04	16.10	15.67	16.82	17.45	17.60	18.06
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
33	Environmental Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
34	**Total**	6.39	6.69	9.73	10.22	11.74	12.27	13.38	14.68	15.27	15.04	16.10	15.67	16.82	17.45	17.60	18.06
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
37	PPA	(0.54)	0.05	(0.37)	0.73	0.49	0.86	0.35	0.61	0.57	1.83	0.71	1.62	1.21	1.62	1.80	2.41
38	Environmental Surcharge	0.49	0.85	2.68	2.62	3.92	3.96	4.38	5.67	5.87	5.59	6.35	6.03	6.71	7.15	7.21	7.62
39	**Total**	5.85	6.74	9.36	10.95	12.23	13.13	13.72	15.28	15.84	16.87	16.81	17.29	18.03	19.08	19.40	20.47

UW Transaction

December 2007

($M)

		2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	**1. Cash Payment/ Credit Escrow Draws**	-	-	301.5	-
2	**2. WKE Residual Value Obligation**				
3	**WKE Gen. Capex - Cum.**				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	**3. LG&E Rental Income Advance**				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	**4. Fuel & Other Inventories**	-	-	55.0	-
20	**5. Cancellation of Settlement Prom. Note**	-	-	16.0	-
21	**6. Coleman Scrubber Completion**	-	-	97.5	-
22	**7. LG&E Emissions Allowance**	-	-	10.9	-
23	**8. Expense Unamortized Mktg Payment/ Settlement Note**			(15.7)	
24	**9. Assurances Agreement**	-	-	4.3	-
25					
26	**Total Residual Value Obligation**	154.1	161.8	161.8	-
27	**Cancellation of RV Obligation**				
28	Reclassification as Equity	-	-	161.8	-
29					
30	**Net WKE Obligation**	154.1	161.8	-	-
31					

UW Transaction

($M)	2007	2008H1	Transaction	2008 H2
		0		0
Unwind Allocation	-	-	-	0.669
Pre-Transaction Allocation	1.000	0.331	-	-
Transaction Index	-	-	1.000	-

32			
33	**B. Transaction Cash Flows**		
34	Cash Balances Pre-Transaction		134.9
35	Transaction Proceeds		301.5
36	Smelter Payment (Assurances Agreement)		(4.3)
37	Consent Fee to Lease-Equity Parties		-
38	Lump-Sum Member Rebate		-
39	Net DSL Termination		-
40	Century/Century Reactive Power Transaction Refund		(0.3)
41	Income Tax		(1.1)
42	Net Transaction Cash		295.9
43	Debt Restructuring:		
44	Debt Reduction (Net)		(186.2)
45	Underwriting Costs	1.75%	(4.6)
46	Bond Insurance	0.80%	(5.0)
47	ARVP Defeasance Premium		-
48	Total		(195.8)
49	Restricted Cash Balances:		
50	Transition Reserve		(35.0)
51	Economic Reserve		(75.0)
52	Unrestricted Cash Balances Post-Transaction		125.0
53			
54	**C. Debt Restructuring:**		
55	Beginning Balance - GAAP		1,051.1
56	Cancellation of Settlement Prom. Note		(16.0)
57	Capitalize Accrued Interest on RUS New Note		7.2
58	Step-Up RUS New Note to Stated Basis:		
59	GAAP RUS New Note		
60	Ending Balance		791.4
61	Accrued Interest		7.2
62	Total		798.6
63	Stated RUS New Note		
64	Ending Balance		794.7
65	Accrued Interest		7.0
66	Total		801.7
67	Step-Up		3.1
68	Beginning Balance - Stated		1,045.3
69	Cash Flow:		
70	Prepay RUS New Note		(449.7)
71	Defease ARVP		-
72	Issue Capital Markets Debt		263.5
73	Net		(186.2)
74	Ending Balance - Stated		859.2
75	Step-Down Remaining RUS New Note to GAAP Basis:		(1.3)
76	Ending Balance - GAAP		857.8
77			

UW Transaction

	($M)		2007	2008H1	Transaction	2008 H2
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				
121						
122	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
123						
124	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
125						
126	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production-Fixed

December 2007

Production - Fixed

($M)

		2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	*NOx Removal Equipment Capital*		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	*Plant Maintenance*		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	**Depreciation**																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	Blended Depreciation Adj.		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

	($M)	2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																		
2	Beginning Balance		-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest		-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal		(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service		(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																			
9	Fixed/ Insured (Tranche 2)																		
10	Beginning Balance		-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)		0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest		-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal		(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service		(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																			
17	RUS -- GAAP																		
18	Beginning Balance		791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon		0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)		0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest		-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest		440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service		440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																			
25	Variable																		
26	Beginning Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon		0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																			
33	PCB																		
34	Beginning Balance		142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon		0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest		-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal		-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service		-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																			
41	ARVP																		
42	Beginning Balance		101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion		-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																			
51	Total																		
52	Beginning Balance		1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion		-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal		177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest		-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service		177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance		857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																			

Unwind Debt

December 2007

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
59	Supporting Schedules																			
60	Amortization of Financing Costs																			
61	Fixed/ Insured (Tranche 1)																			
62	Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63	BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64	YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65	Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67	EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71	BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72	YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73	Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74	Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75	EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																				
77	Variable																			
78	Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83	EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																				
85																				
86	Amortization of Financing Costs																			
87	Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88	Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89	Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																				
91	Interest Expense																			
92	Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93	ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94	Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95	AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96	Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97	Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

December 2007

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	Defeasance Income	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	Additions	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	Non-Incremental	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476)	0	0
				185,791,428		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

- Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
  For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

		Source:	2005/ Othe	2008	2007	2008H1	Transactio 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Electricity Sales, Purchases, and Production																						
1	Sales																						
2	Rural																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.160	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142	3.151	3.142	3.142	3.142
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	365	366	366	366	366	366	366	366	366	366	366	365	366	355
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.16						2.789	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155	4.166	4.155	4.155	4.155
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
18																							
19	Offsystem (TWh)	file: annual output - 12-15-07.xls		1.93	1.16	0.71		1.06	1.49	1.61	1.32	1.21	1.20	1.17	1.12	1.08	0.92	0.99	0.70	0.72	0.75	0.68	0.70
20																							
21	Purchases & Production																						
22	Purchases (TWh)																						
23	Market	file: annual output - 12-15-07.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.46	0.38	0.54	0.37	0.42	0.42	0.72	0.47	0.66	0.53	0.55	0.62	0.71
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 12-15-07.xls			-	-		8.07	11.80	12.10	11.63	11.71	11.65	11.88	11.87	11.95	11.56	11.97	11.58	11.86	11.94	11.90	11.92
26	Loss Rate (%)	file: annual output - 12-15-07.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	Fuel Consumption (MMBtu)	file: annual output - 12-15-07.xls						89.9	131.5	134.0	129.1	129.4	128.1	130.5	130.5	131.2	127.3	131.6	127.3	130.4	131.3	130.7	131.1
29																							
30	Startup Costs (M$)	file: annual output - 12-15-07.xls			-	-		4.36	6.54	6.84	7.89	6.54	6.91	7.01	6.17	6.97	8.06	6.81	8.66	7.68	7.68	8.42	8.22
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		14,032	18,797	19,862	18,824	19,358	18,296	19,317	20,336	20,806	19,359	20,823	18,767	19,356	20,501	20,755	20,354
35	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	17,125	17,125	18,352	18,352	18,352
36	NOX																						
37	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		4,932	13,610	13,606	12,916	12,895	13,063	12,974	13,115	12,988	13,014	13,060	12,813	13,164	13,188	12,936	13,288
38	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		4,651	11,072	11,072	11,071	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 12-15-07.xls						1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 12-15-07.xls		67.8347	77.90	200.00		47.55	53.53	53.88	51.18	49.81	45.03	48.35	50.54	50.35	50.86	48.44	50.63	54.49	62.05	58.69	62.64
46	Variable Production ($/ MWh sales)	file: annual output - 12-15-07.xls			-	2.27		2.27	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
47	SO2 Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	778		778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	*Coal used (ktons)*	file: annual output - 12-15-07.xls	100%					4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
51																							
52	**Sales Rates & Related**																						
53																							
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	2.00%	0.00%	0.00%	0.00%	0.98%	0.00%	9.99%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	Market ($/ MWh)	file: annual output - 12-15-07.xls		43.30	42.91	37.82		48.40	51.34	49.47	50.22	49.48	52.67	53.42	55.37	54.46	55.41	56.98	59.56	60.21	58.91	62.81	62.27
57																							
58	Rural																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	*Escalated by GRAs*																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	*Smelters*																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	1.77	2.63	2.38	2.24	3.16	2.88	3.14	0.15	3.17	2.16	3.45	2.50	3.69
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	5.11	7.30	7.30	7.30	7.30	7.30	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76
73																							
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback ransaction		3.68	3.68000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	(0.00)	(0.00)	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	(0.00)	-	(0.00)	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	*W/o Purchased Power (Total Sales Denom.)*	*Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0*	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84	Allocation of Revenues on '																						
85	Total																						
86	NOx + SO3	file: annual output - 12-15-07.xls																					
87	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.88	5.17	5.05
88	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
89	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
91	Net Allowances	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
92	Total	*file: annual output - 12-15-07.xls*						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
93	**Allowed in ES**																						
94	NOx + SO3	file: annual output - 12-15-07.xls																					
95	VOM	file: annual output - 12-15-07.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 12-15-07.xls						0.21	7.23	6.10	3.97	3.65	3.81	3.66	7.80	7.07	7.35	7.47	7.04	7.93	8.34	8.31	8.96
97	SO2	file: annual output - 12-15-07.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 12-15-07.xls						17.35	25.66	27.66	29.29	32.11	32.82	33.78	37.85	38.87	39.23	40.97	40.87	42.83	45.04	45.17	47.38
99	Net Allowance Costs in Excess of 2009	file: annual output - 12-15-07.xls						(14.49)	(25.74)	(4.06)	(4.64)	(4.06)	(4.63)	(4.07)	1.80	1.86	0.62	0.88	0.24	0.31	0.29	0.27	0.21
100	Total	file: annual output - 12-15-07.xls						4.06	10.44	33.45	32.19	35.49	35.62	37.46	51.54	52.19	51.21	53.95	52.65	55.79	58.54	58.92	61.60
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Le				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	*Amortization*	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances		-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	*Base Payment*	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.60	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.15																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.66	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	*Principal Payment*	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.19	11.41	12.77	-	25.85															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	Net Confomring Receipts	Big Rivers' estimate		-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Adjustment (8/2007)			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 8-29-07_Rev1.xls						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	Property Tax			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.65	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	*Clmn FGD Equipment Capital*	*file: Fin Model inputs BREC Nov-07 w outage shift.xls*		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	Phase I	Per Crockett Memo dated 11/12/07		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-		-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	*Capex Purposes*	*Unwind spreadsheet -- 8-29-07_Rev1.xls*		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-																	
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	-
307	Green River Coal Settlement	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	*MISO Credit Fee*		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson	file: annual output - 12-15-07.xls		-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.11)	(20.39)	(28.05)	(0.40)	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.28%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Harrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,760.4	1,760.2																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	828.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	Historic Balance Sheet	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	Credit Escrow	Economic Reserve	-	-	-	-	75.0	71.6	62.1	45.7	27.3	0.4	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	Long-Term Debt																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

Inputs

December 2007

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc Included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.59		8.69	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	27.3	0.4	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	1.2	0.0	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(20.4)	(28.0)	(0.4)	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	27.3	0.4	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 12-15-07.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	Depreciation																						

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic		6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		25.36	25.39	8.58		28.58	9.01														
475	HMP&L Station Two	Historic		1.58	1.64	0.54		0.93	0.31														
476	Other	Historic		5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3 10						0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.80	0.00	0.00																	
490	Temporary Differences																						
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.38	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	5.58	5.70																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year						-	-	-	-	1.09	1.14	1.42	1.60	1.78	1.58	2.17	1.91	2.39	2.67	2.73	3.00

Fuel Inventory

December 2007

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.70	1.71	1.81	1.82	1.84	1.88	1.92	1.90	1.92	1.95	1.97	1.99	2.01
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,100	10,999	11,019	11,045	11,021	11,060	11,069	11,037	11,015	11,028	11,021	11,037	11,003
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.20	22.00	22.04	22.09	22.04	22.12	22.14	22.07	22.03	22.06	22.04	22.07	22.01
7	Coal Consumed [from PCM (000s tons)]		4,072	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	129,052	129,383	128,057	130,536	130,460	131,239	127,332	131,626	127,278	130,423	131,329	130,729	131,111
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(129,052)	(129,383)	(128,057)	(130,536)	(130,460)	(131,239)	(127,332)	(131,626)	(127,278)	(130,423)	(131,329)	(130,729)	(131,111)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6
19	Fuel Purchased	-	133.3	197.7	220.4	219.2	221.7	231.6	238.1	239.8	246.5	244.0	250.5	244.3	254.5	258.8	259.6	263.0
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(217.2)	(221.2)	(228.1)	(237.6)	(239.3)	(245.0)	(242.6)	(250.9)	(243.7)	(253.3)	(258.1)	(259.0)	(262.3)
22	EB	55.0	55.0	55.8	61.0	63.0	63.6	67.1	67.7	68.2	69.7	71.1	70.6	71.2	72.4	73.1	73.6	74.4

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	Calendar Year	**2007**	**2008H1**	**Transaction**	**2008 H2**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
1	**I. Sales (TWH)**																			
2																				
3	Rural	2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																				
5	Large Industrial	0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																				
7	Century	-	-	-	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
8																				
9	Alcan	-	-	-	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
10																				
11	Market	1.16	0.71	-	1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
12																				
13	Total Sales	4.53	1.80	-	8.28	12.29	12.49	11.58	11.80	11.70	12.02	11.96	11.89	11.49	12.02	11.65	11.83	11.87	11.92	12.00
14																				

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		2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Calendar Year																			
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
15	**II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)**																			
16																				
17	General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	29.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18																				
19	FAC ($/ MWH)				5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
20																				
21	PPA ($/ MWH)				(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																				
23	Environmental Surcharge Adjustment ($/ MWH)																			
24	Rural				0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
25	Large Industrial				0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
26	Smelters				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
27																				
28	Rural																			
29	Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
30	Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	9.51	9.51	9.51	9.51	9.51	9.51	9.51
31	Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	26.32	26.32	26.32	26.32	26.32	26.32	26.32
32																				
33	Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
34	MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
35	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
36	GRA	-	-		-	-	-	-	-	-	-	-	-	10.75	10.74	10.73	10.73	10.72	10.72	10.71
37																				
38	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
39	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
40	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
42	Net	-	-		-	0.16	0.53	0.89	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
43																				
44	Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.01	43.62	47.83	48.50	49.69	50.08	61.34	61.51	62.02	62.35	62.60	63.05	63.59
45	TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.01	43.62	47.83	48.50	49.69	50.08	61.34	61.51	62.02	62.35	62.60	63.05	63.59
47																				
48	Large Industrial																			
49	Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
50	Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	13.10	13.10	13.10	13.10	13.10	13.10	13.10
51	Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	17.70	17.70	17.70	17.70	17.70	17.70	17.70
52																				
53	Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
54	Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
56	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
57	GRA	-	-		-	-	-	-	-	-	-	-	-	9.11	9.11	9.11	9.12	9.11	9.11	9.11
58																				
59	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
60	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
61	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
63	Net	-	-		-	0.16	0.53	0.89	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
64																				
65	Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	31.40	38.04	42.26	42.96	44.16	44.59	54.22	54.41	54.95	55.33	55.57	56.04	56.60
66	TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	31.40	38.04	42.26	42.96	44.16	44.59	54.22	54.41	54.95	55.33	55.57	56.04	56.60
68																				

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	Calendar Year	**2007**	**2008H1**	**Transaction**	**2008 H2**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
75	GRA	-	-		-	-	-	-	-	-	-	-	-	10.23	10.22	10.22	10.21	10.20	10.20	10.20
76																				
77	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
78	Environmental Surcharge				0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
81	Net				-	0.16	0.53	0.89	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.28	41.89	46.09	46.76	47.95	48.35	59.08	59.24	59.76	60.10	60.34	60.79	61.33
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.28	41.89	46.09	46.76	47.95	48.35	59.08	59.24	59.76	60.10	60.34	60.79	61.33
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
89	TIER Adjustment	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
91	FAC				5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
92	PPA	-	-		(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Environmental Surcharge				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Surcharge 1	-	-		0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Surcharge 2				1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	52.51	59.65	60.56	61.79	64.01	64.99	66.46	68.90	70.47	73.98	75.55	79.03	81.33
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	47.04	53.99	55.80	56.86	58.60	59.22	63.75	65.44	66.42	68.70	69.66	71.85	73.35
102																				

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	91.7	113.2	126.8	131.1	137.3	141.2	176.6	180.5	185.9	190.7	195.3	200.5	206.1
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	34.6	44.3	50.7	53.0	56.1	58.1	72.6	*74.7*	77.3	79.7	*82.0*	*84.6*	*87.4*
108	Smelters	-	-	-	171.7	257.7	277.7	-	-	-	-	-	-	-	-	-	-	-	-	-
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	414.9	479.3	475.1	499.2	507.6	505.1	483.0	531.4	510.3	542.3	549.3	571.3	586.8
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	7.8	9.793	11.4	13.2	14.4	15.1	15.8	17.7	18.3	19.7	20.4	21.5
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	548.6	646.2	664.3	696.1	705.6	711.2	740.7	795.1	784.9	823.8	838.8	869.3	893.6
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	214.3	224.7	233.4	244.6	242.3	244.0	241.4	252.6	251.7	256.7	257.9	265.4	270.4
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	7.2	8.9	8.2	8.3	8.3	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
122	Carbon Tax			-	-	-	-	-	*91.2*	*103.2*	*116.7*	*131.9*	*144.0*	*151.8*	*172.1*	*179.1*	*195.6*	*209.6*	*222.5*	*238.1*
123	Carbon Allowance Cost			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(8.0)	(2.0)	(2.3)	(3.5)	(1.6)	(1.9)	1.4	(4.6)	(0.0)	(3.4)	(0.1)	(3.4)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	406.7	499.9	531.8	558.3	582.9	596.9	624.9	646.6	664.9	688.9	714.8	738.8	766.3
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	146.3	132.5	137.8	122.7	114.3	115.8	148.5	120.0	135.0	124.0	130.5	127.3
136																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
137																				
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	146.3	132.5	137.8	122.7	114.3	115.8	148.5	120.0	135.0	124.0	130.5	127.3
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	*Total Capital Expenditures*	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	47.2	11.9	18.9	85.7	92.4	96.9	100.0	85.0	76.1	75.4	102.4	72.5	89.3	76.1	83.1	78.0
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	Post-Finance Cash Flow	42.0	(3.5)	-	8.1	(46.5)	(39.5)	27.3	34.0	38.5	41.6	26.6	17.7	17.0	44.0	14.1	30.9	17.7	24.6	19.6
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
167	Net Before Transition Reserve			25.1	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
168																				
169	Ending Cash Balances (Incl. Transition	138.4	134.9	160.0	173.6	139.7	119.3	181.5	228.8	267.3	309.0	335.6	353.3	370.3	414.2	428.3	459.3	477.0	501.6	521.2
170	Reserve)																			

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	*1.000*	*0.331*	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
171	**IV. Income Statement (M$)**																			
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.5	87.1	88.8	94.1	113.2	126.8	131.1	137.3	141.2	176.6	180.5	185.9	190.7	195.3	200.5	206.1
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	35.5	44.3	50.7	53.0	56.1	58.1	72.6	74.7	77.3	79.7	82.0	84.6	87.4
176	Smelters	-	-	-	170.6	254.9	275.0	-	-	-	-	-	-	-	-	-	-	-	-	-
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	414.9	479.3	475.1	499.2	507.6	505.1	483.0	531.4	510.3	542.3	549.3	571.3	586.8
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
181	WKEC Lease (Net)	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	7.767	9.793	11.442	13.223	14.363	15.120	15.847	17.730	18.332	19.656	20.415	21.470
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	551.4	645.6	663.8	695.6	705.1	710.7	740.2	794.6	784.3	823.3	838.2	868.7	893.0
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
189	Carbon Tax			-	-	-	-	-	91.2	103.2	118.7	131.9	144.0	151.8	172.1	179.1	195.6	209.6	222.5	238.1
190	Carbon Allowance Cost			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
192	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	*Transmission O&M*	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	*(6.3)*	*(2.3)*	-	*(0.6)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*	*(0.9)*
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	486.2	592.9	614.1	644.8	672.6	685.2	726.2	745.8	769.1	789.8	819.3	835.7	870.3
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	100.0	66.1	49.7	50.7	32.5	25.5	13.9	48.8	15.2	33.5	18.9	33.0	22.7

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
210																				
211	**V. Balance Sheet (M$)**																			
212																				
213	Assets																			
214	Property																			
215	Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216	Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217	Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218	Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219	Current																			
220	Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	140.6	186.2	222.9	262.7	287.3	302.9	317.8	359.5	371.2	399.7	414.9	436.9	453.7
222	Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223	Economic Reserve	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	45.5	53.2	54.5	57.0	57.7	58.0	60.4	64.9	63.9	67.1	68.2	70.7	72.6
225	Regulatory Asset	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
226	Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0
227	Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228	Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229	Credits																			
230	AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231	Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232	Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233	Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234	LEM Settlement Note/Marketing Paymer	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	*Total Assets*	*1,300.0*	*1,306.8*	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,728.6	1,772.2	1,818.0	1,844.8	1,862.8	1,871.5	1,913.5	1,922.3	1,948.6	1,961.5	1,986.3	2,003.4
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	516.6	582.7	632.4	683.2	715.6	741.1	755.0	803.8	819.1	852.5	871.4	904.5	927.2
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241	*Sale-Leaseback Obligation*	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242	Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243	Current & Accrued Liabilities																			
244	*Accounts Payable*	11.7	11.7	11.7	57.2	57.3	59.1	58.3	73.7	76.9	81.5	85.4	87.2	91.2	94.0	97.4	100.4	104.7	107.1	112.1
245	Regulatory Liability				1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
246	Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247	Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
248	Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249	Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250	*Deferred TIER Rebate Payable*				1.7	5.8	9.9	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
251	WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252	Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253	Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,728.6	1,772.2	1,818.0	1,844.8	1,862.8	1,871.5	1,913.5	1,922.3	1,948.6	1,961.5	1,986.3	2,003.4
255																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	6.0	7.6	1.3	2.5	0.6	0.4	2.4	4.5	(1.0)	3.2	1.1	2.5	1.9
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	0.8	(15.4)	(3.1)	(4.6)	(4.0)	(1.8)	(4.1)	(2.8)	(3.4)	(3.0)	(4.3)	(2.4)	(5.1)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(8.0)	(2.0)	(2.3)	(3.5)	(1.6)	(1.9)	1.4	(4.6)	(0.0)	(3.4)	(0.1)	(3.4)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	181.5	228.8	267.3	309.0	335.6	353.3	370.2	414.2	428.3	459.2	477.0	501.6
272	Ending	138.4	134.9	160.0	173.6	139.7	119.3	181.5	228.8	267.3	309.0	335.6	353.3	370.2	414.2	428.3	459.2	477.0	501.6	521.2
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	100.0	66.1	49.7	50.7	32.5	25.5	13.9	48.8	15.2	33.5	18.9	33.0	22.7
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	Plus: Imputed Rate Increase in 2010				-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
282	Total				40.7	60.5	59.8	144.8	110.2	93.0	93.1	73.9	66.0	53.4	87.2	52.5	69.5	53.7	66.6	54.7
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	159.3	125.2	108.6	109.4	90.9	83.7	71.9	106.6	72.8	90.9	76.1	90.1	79.4
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	2.69	2.12	1.84	1.87	1.56	1.44	1.24	1.84	1.26	1.58	1.33	1.58	1.40
291																				
292	Conventional TIER																			
293	Earnings				10.6	15.8	13.3	100.0	66.1	49.7	50.7	32.5	25.5	13.9	48.8	15.2	33.5	18.9	33.0	22.7
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	144.8	110.2	93.6	93.7	74.6	66.7	54.1	88.0	53.3	70.4	54.6	67.5	55.7
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	159.3	125.2	109.3	110.1	91.6	84.5	72.7	107.4	73.6	91.7	77.0	91.0	80.4
299	Divided by																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	2.69	2.12	1.85	1.88	1.57	1.45	1.25	1.86	1.28	1.60	1.35	1.60	1.42
305																				

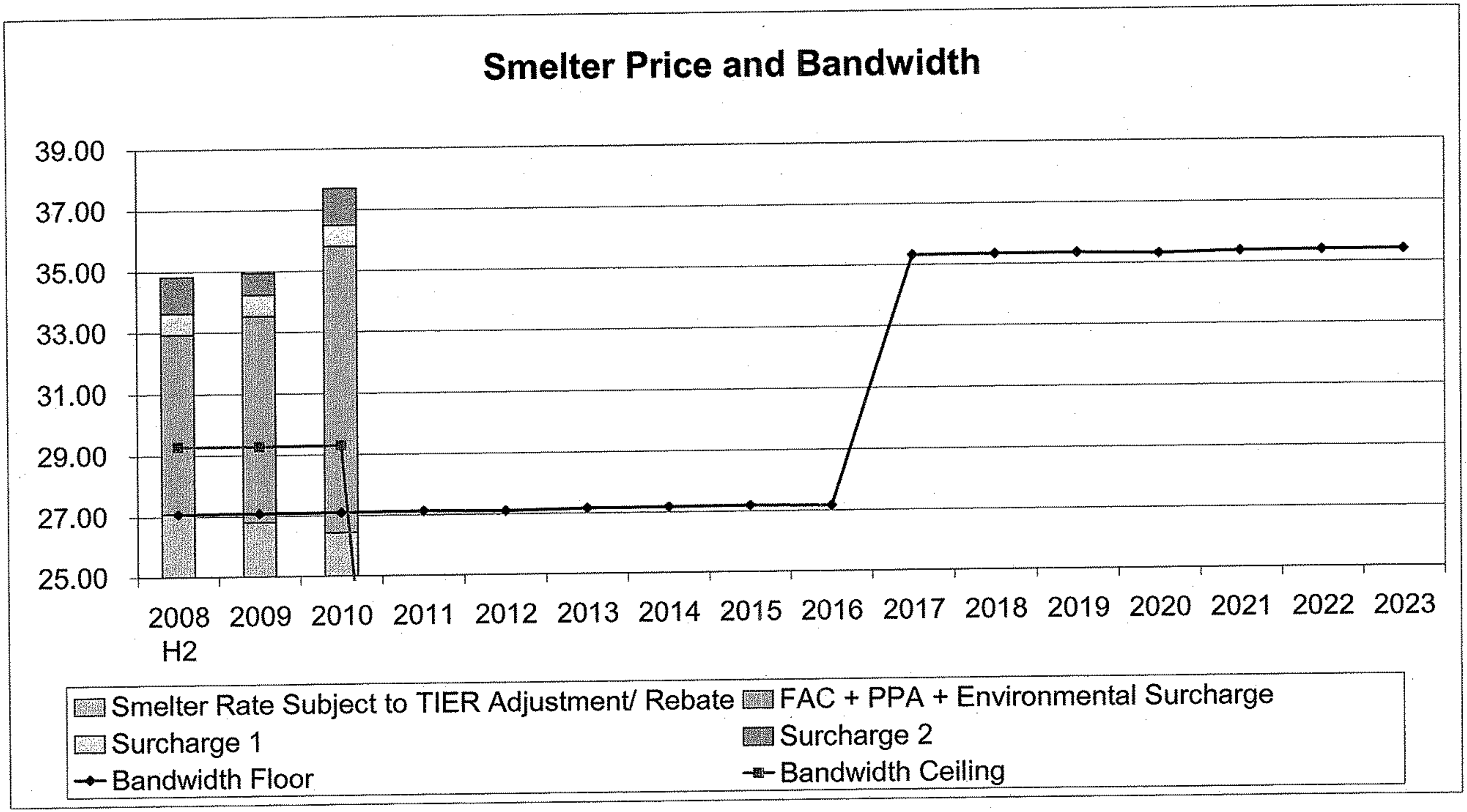
Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
															Transaction Closing Date:			4/30/2008	
DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
Cash Available for Debt Service																			
Receipts less Disbursements				84.6	88.0	77.5	141.9	146.3	132.5	137.8	122.7	114.3	115.8	148.5	120.0	135.0	124.0	130.5	127.3
Economic Reserve				5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
Net				90.2	100.5	96.6	176.8	159.6	132.5	137.5	122.3	113.9	115.4	148.1	119.6	134.5	123.5	130.0	126.8
Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
Total				99.1	113.8	110.5	191.3	174.7	148.2	153.8	139.3	131.7	134.0	167.5	139.9	155.8	145.9	153.5	151.5
Divided by																			
Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
DSCR				2.06	1.59	1.53	2.62	2.38	2.00	2.06	1.85	1.73	1.74	2.15	1.78	1.95	1.81	1.87	1.82
Days Cash on Hand																			
Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	150.4	205.1	248.1	288.1	322.3	344.4	361.8	392.2	421.3	443.8	468.1	489.3	511.4
Line of Credit				66.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Total	117.5	136.7	147.5	233.8	256.6	229.5	250.4	305.1	348.1	388.1	422.3	444.4	461.8	492.2	521.3	543.8	568.1	589.3	611.4
Divided by																			
Total Operating Expense																			
PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
Total	182.8	69.2	-	293.6	439.0	450.9	444.4	458.4	466.9	481.9	495.0	493.9	513.0	510.8	525.8	528.7	542.7	544.7	562.3
Days Cash on Hand (including Line o	234.5	721.0		290.6	213.4	185.8	205.6	242.9	272.1	294.0	311.4	328.4	328.6	351.7	361.8	375.4	382.1	394.9	396.9
Days Cash on Hand (excluding Line c	234.5	721.0		207.4	130.2	104.8	123.5	163.3	193.9	218.2	237.6	254.5	257.4	280.3	292.4	306.3	314.8	327.9	332.0

	Calendar Year	2007	2008H1	Transac tion	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	*Interest*		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	Beginning Principal		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	*859.1*	*851.2*	*839.0*	*826.0*	*812.3*	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

Smelter Rate Structure

December 2007

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	29.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Alcan	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Total Energy (TWh)	4.898	7.297	7.297	-	-	-	-	-	-	-	-	-	-	-	-	-
5 Total Demand (GW)	6.847	10.200	10.200	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	13.10	13.10	13.10	13.10	13.10	13.10	13.10
13 Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	17.70	17.70	17.70	17.70	17.70	17.70	17.70
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
17 Less: Regulatory Account Charge	-	-	-	-	-	0.21	0.21	0.20	-	-	-	-	-	-	-	(0.00)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	30.51	30.53	30.55	30.56	30.58	30.61	39.73	39.74	39.76	39.80	39.79	39.81	39.82
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.11	27.09	27.15	27.16	27.18	27.16	35.31	35.32	35.34	35.30	35.37	35.38	35.39
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.36	27.34	27.40	27.41	27.43	27.41	35.56	35.57	35.59	35.55	35.62	35.63	35.64
23 Plus TIER Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Plus Surcharge 1	0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Plus Surcharge 2	1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-



Smelter Price and Bandwidth

Smelter Rate Structure

December 2007

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	129.6	157.5	177.5	184.2	193.3	199.3	249.1	255.2	263.2	270.4	277.3	285.2	293.6
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	75.8	115.1	102.9	456.6	501.5	486.2	511.4	511.8	511.4	491.0	539.4	521.1	552.9	560.9	583.6	599.5
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	586.3	659.0	663.8	695.6	705.1	710.7	740.2	794.6	784.3	823.3	838.2	868.7	893.0
Total Expenses	315.2	473.3	486.4	486.2	592.9	614.1	644.8	672.6	685.2	726.2	745.8	769.1	789.8	819.3	835.7	870.3
Net Margin Before TIER Adjustment	12.3	21.7	23.3	100.0	66.1	49.7	50.7	32.5	25.5	13.9	48.8	15.2	33.5	18.9	33.0	22.7
Interest + Margin	52.4	81.2	82.7	159.3	125.2	108.6	109.4	90.9	83.7	71.9	106.6	72.8	90.9	76.1	90.1	79.4
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	2.69	2.12	1.84	1.87	1.56	1.44	1.24	1.84	1.26	1.58	1.33	1.58	1.40
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	(85.8)	(51.9)	(35.6)	(36.7)	(18.4)	(11.5)	0.0	(34.9)	(1.4)	(19.7)	(5.2)	(19.3)	(9.1)
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Offset to Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Adjustments	(1.0)	(1.5)	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	(85.8)	(51.9)	(35.6)	(36.7)	(18.4)	(11.5)	0.0	(34.9)	(1.4)	(19.7)	(5.2)	(19.3)	(9.1)
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rebate to Members/Smelters ($/MWh)																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	9.51	9.51	9.51	9.51	9.51	9.51	9.51
10	Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	26.32	26.32	26.32	26.32	26.32	26.32	26.32
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
14	GRA	-	-	-	-	-	-	-	-	-	10.75	10.74	10.73	10.73	10.72	10.72	10.71
15	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
16	Env. Surcharge	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
20	Net	-	(0.01)	(0.02)	(0.04)	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
21	Effective Rate	36.07	36.11	36.09	36.07	43.62	47.83	48.50	49.69	50.08	61.34	61.51	62.02	62.35	62.60	63.05	63.59
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	13.10	13.10	13.10	13.10	13.10	13.10	13.10
26	Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	17.70	17.70	17.70	17.70	17.70	17.70	17.70
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
30	GRA	-	-	-	-	-	-	-	-	-	9.11	9.11	9.11	9.12	9.11	9.11	9.11
31	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
32	Env. Surcharge	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
36	Net	-	0.02	0.06	0.09	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
37	Effective Rate	30.58	30.48	30.54	30.59	38.04	42.26	42.96	44.16	44.59	54.22	54.41	54.95	55.33	55.57	56.04	56.60
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
43	GRA	-	-	-	-	-	-	-	-	-	10.23	10.22	10.22	10.21	10.20	10.20	10.20
44	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
45	Env. Surcharge	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
49	Net	-	0.00	0.00	0.00	7.51	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
50	Effective Rate	34.44	34.40	34.39	34.39	41.89	46.09	46.76	47.95	48.35	59.08	59.24	59.76	60.10	60.34	60.79	61.33
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	-	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total	1.26	(0.17)	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
12	Debit Power Purchase Expense						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
13																	
14	Net Income	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
19	Regulatory Asset	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Total	-	-	-	-	-	(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
24	Regulatory Liability	1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	-	-	(0.8)	(1.6)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.3	11.5	11.5	11.8	11.7	11.7	11.3	11.8	11.4	11.6	11.6	11.7	11.8
2	**Sales (TWh)**	8.3	12.3	12.5	11.6	11.8	11.7	12.0	12.0	11.9	11.5	12.0	11.6	11.8	11.9	11.9	12.0
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold	16.62	16.56	17.77	18.48	18.86	19.69	20.25	20.26	20.44	20.91	20.99	21.48	21.66	21.71	22.13	22.46
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	6.88	8.58	7.83	7.94	7.95	7.94	8.31	8.12	8.35	8.29	8.44	8.57	8.57
13																	
14	Total Costs for Passthrough ($/ MWh Sold	1.21	1.80	1.38	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
20																	
21	Total Costs for Passthrough ($/ MWh Sold	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
29	Environmental Surcharge	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
30	**Total**	6.39	6.69	9.73	10.39	11.05	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
33	Environmental Surcharge	0.49	0.85	2.68	2.62	2.90	2.96	3.06	4.24	4.25	4.30	4.40	4.42	4.58	4.79	4.83	5.04
34	**Total**	6.39	6.69	9.73	10.39	11.05	11.93	12.60	13.78	13.98	14.49	14.66	15.19	15.53	15.78	16.23	16.78
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
37	PPA	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Environmental Surcharge	0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
39	**Total**	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-

UW Transaction

	($M)	2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	**1. Cash Payment/ Credit Escrow Draws**	-	-	301.5	-
2	**2. WKE Residual Value Obligation**				
3	**WKE Gen. Capex - Cum.**				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	**3. LG&E Rental Income Advance**				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	**4. Fuel & Other Inventories**	-	-	55.0	-
20	**5. Cancellation of Settlement Prom. Note**	-	-	16.0	-
21	**6. Coleman Scrubber Completion**	-	-	97.5	-
22	**7. LG&E Emissions Allowance**	-	-	10.9	-
23	**8. Expense Unamortized Mktg Payment/ Settlement Note**			(15.7)	
24	**9. Assurances Agreement**	-	-	4.3	-
25					
26	**Total Residual Value Obligation**	154.1	161.8	161.8	-
27	**Cancellation of RV Obligation**				
28	Reclassification as Equity	-	-	161.8	-
29					
30	**Net WKE Obligation**	154.1	161.8	-	-
31					

UW Transaction

	($M)		2007	2008H1	Transaction	2008 H2
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
32						
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction				134.9	
35	Transaction Proceeds				301.5	
36	Smelter Payment (Assurances Agreement)				(4.3)	
37	Consent Fee to Lease-Equity Parties				-	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				(0.3)	
41	Income Tax				(1.1)	
42	Net Transaction Cash				295.9	
43	Debt Restructuring:					
44	Debt Reduction (Net)				(186.2)	
45	Underwriting Costs	1.75%			(4.6)	
46	Bond Insurance	0.80%			(5.0)	
47	ARVP Defeasance Premium				-	
48	Total				(195.8)	
49	Restricted Cash Balances:					
50	Transition Reserve				(35.0)	
51	Economic Reserve				(75.0)	
52	Unrestricted Cash Balances Post-Transaction				125.0	
53						
54	**C. Debt Restructuring:**					
55	Beginning Balance - GAAP				1,051.1	
56	Cancellation of Settlement Prom. Note				(16.0)	
57	Capitalize Accrued Interest on RUS New Note				7.2	
58	Step-Up RUS New Note to Stated Basis:					
59	GAAP RUS New Note					
60	Ending Balance				791.4	
61	Accrued Interest				7.2	
62	Total				798.6	
63	Stated RUS New Note					
64	Ending Balance				794.7	
65	Accrued Interest				7.0	
66	Total				801.7	
67	Step-Up				3.1	
68	Beginning Balance - Stated				1,045.3	
69	Cash Flow:					
70	Prepay RUS New Note				(449.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				263.5	
73	Net				(186.2)	
74	Ending Balance - Stated				859.2	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.3)	
76	Ending Balance - GAAP				857.8	
77						

UW Transaction

	($M)		2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				

121

122 (b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder

123

124 (c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.

125

126 (d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.

Production-Fixed

Production - Fixed

	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

December 2007

Capex & Depreciation

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	Depreciation																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	Blended Depreciation Adj.		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

December 2007

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																			
2	Beginning Balance			-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest			-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service			(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																				
9	Fixed/ Insured (Tranche 2)																			
10	Beginning Balance			-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)			0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest			-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service			(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																				
17	RUS – GAAP																			
18	Beginning Balance			791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon			0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)			0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest			-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest			440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service			440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																				
25	Variable																			
26	Beginning Balance			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	*Coupon*			0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																				
33	PCB																			
34	Beginning Balance			142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon			0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal			-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																				
41	ARVP																			
42	Beginning Balance			101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%		5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	Total																			
52	Beginning Balance			1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal			177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service			177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance			857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																				

Unwind Debt

			2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($M)		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Unwind Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Pre-Transaction Allocation		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
59	Supporting Schedules																			
60	Amortization of Financing Costs																			
61	Fixed/ Insured (Tranche 1)																			
62	Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63	BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64	YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65	Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67	EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71	BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72	YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73	Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74	Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75	EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																				
77	Variable																			
78	Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83	EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																				
85																				
86	Amortization of Financing Costs																			
87	Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88	Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89	Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																				
91	Interest Expense																			
92	Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93	ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94	Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95	AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96	Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97	Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	*Defeasance Income*	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	*Net Taxable Income*	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	*Additions*	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	*Est. Book Tax*	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	*Non-Incremental*	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	*Environmental*	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476)	0	0
				185,791,428		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

December 2007

	Electricity Sales, Purchases, and Production	Source:	2005/ Othe	2006	2007	2008H1	Transactior 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Sales																						
2	Rural																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109	3.142	3.142	-	-	-	-	-	-	-	-	-	-	-	-	-
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	366	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.16						2.789	4.155	4.155	-	-	-	-	-	-	-	-	-	-	-	-	-
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484	484	484	-	-	-	-	-	-	-	-	-	-	-	-	-
18																							
19	Offsystem (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		1.93	1.16	0.71		1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
20																							
21	Purchases & Production																						
22	Purchases (TWh)																						
23	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.00	-	0.00	-	-	-	0.01	-	0.00	-	0.00	0.00	-
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		8.07	11.80	12.10	11.31	11.53	11.47	11.80	11.74	11.67	11.26	11.80	11.43	11.61	11.65	11.70	11.79
26	Loss Rate (%)	file: annual output - 2-5-08 - No Smelters after 2010.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	Fuel Consumption (MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						89.9	131.5	134.0	125.3	127.4	126.1	129.7	129.0	128.1	123.9	129.8	125.7	127.8	128.1	128.6	129.7
29																							
30	Startup Costs (M$)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4.36	6.54	6.84	7.06	6.35	6.39	6.96	6.10	6.62	7.78	6.80	8.60	7.90	7.35	8.13	8.18
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		14,032	18,797	19,882	18,354	19,098	18,060	19,229	18,959	19,263	17,802	19,391	18,577	19,090	18,763	19,247	18,922
35	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125
36	NOX																						
37	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,932	13,610	13,606	12,599	12,680	12,861	12,837	12,932	12,634	12,608	12,823	12,600	12,824	12,840	12,672	13,095
38	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,651	11,072	11,072	11,072	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		67.8347	77.90	200.00		47.55	53.53	53.88	43.50	7.91	55.27	10.06	11.23	12.34	60.53	14.58	70.29	16.84	66.23	60.74	20.20
46	Variable Production ($/ MWh sales)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	2.27		2.27	2.45	2.60	2.84	3.06	3.14	3.18	3.54	3.64	3.75	3.81	3.90	4.01	4.19	4.22	4.38
47	SO2 Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	778		778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 2-5-08 - No Smelters after 2010.xls	100%					4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,861	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
51																							
52	**Sales Rates & Related**																						
53																							
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	29.02%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	Market ($/ MWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		43.30	42.91	37.82		48.40	51.34	49.47	52.51	59.65	60.56	61.79	64.01	64.99	66.46	68.90	70.47	73.98	75.55	79.03	81.33
57																							
58	Rural																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	Smelters																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	40.39	42.51	43.22	43.69	46.46	46.71	50.93	47.90	51.41	51.12	53.51	52.89	55.16
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	-	-	-	-	-	-	-	-	-	-	-	-	-
73																							
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback transaction		3.68	3.68000	1.21661		2.46	3.66	3.66	3.68	3.68	3.68	3.58	3.69	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	-	-	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	-	-	-	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84	Allocation of Revenues on																						
85	Total																						
86	NOx + SO3	file: annual output - 2-5-08 - No Smelters after 2010.xls																					
87	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	6.72	7.41	7.81	7.90	8.67
89	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactioi	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
91	Net Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
92	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
93	**Allowed in ES**																						
94	NOx + SO3	file: annual output - 2-5-08 - No Smelters after 2010.xls																					
95	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	6.72	7.41	7.81	7.90	8.67
97	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
99	Net Allowance Costs in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
100	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007 xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Lev				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 185																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances		-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007 xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.15																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.65	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.19	11.41	12.77	-	25.65															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	*Net Conforming Receipts*	*Big Rivers' estimate*		-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	65.69	57.38	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	*Fixed Environmental O&M, Clear Skies (Real Basis)*																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (Includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Adjustment (8/2007)			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	*Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls*		*6.59*	*7.38*	*1.89*		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.69	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet -- 8-29-07_Rev1.xls						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	*Property Tax*			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	*3.01*	*3.10*	*3.19*	*3.29*	*3.39*	*3.49*	3.59	3.70	*3.81*	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.76	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin-Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Clmn FGD Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	Phase I	Per Crockett Memo dated 11/12/07		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-			3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	*Phase II*			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	*Environmental*	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-																	
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	-
307	Green River Coal Settlement	*Long Term Debt Schedule Actual 2006 - Budget 2007.xls*		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson	file: annual output - 2-5-08 - No Smelters after 2010 xls		-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.11)	(34.89)	(13.32)	-	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.26%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	*Receivables (days)*	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	*Smelter Retail Agreements, Section 1.1.119*	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	*Property*																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,760.4	1,780.2																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	826.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	Historic Balance Sheet	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	Credit Escrow	Economic Reserve	-	-	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
348	Other Current Assets	*Historic Balance Sheet*	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	Long-Term Debt																						
359	*Existing Debt*	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.58	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	0.5	-	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(34.9)	(13.3)	-	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	**Depreciation**																						

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + In service	Historic		12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic		6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	*0.00*	*0.00*		*0.00*															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		25.36	25.39	8.58		26.58	9.01														
475	HMP&L Station Two	Historic		1.58	1.64	0.54		0.93	0.31														
476	Other	Historic		5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3.10						0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			*0.80*	*0.00*	*0.00*																	
490	Temporary Differences																						
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	*NOL Related*																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	*2006 AMT BB*			4.28	4.69	5.58	5.70																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	*Orrick Herrington/ Deloitte*	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	7.91	8.99	10.06	11.23	12.34	13.48	14.58	15.67	16.84	18.00	19.01	20.20
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Fuel Inventory

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,023	11,004	11,003	11,059	11,007	11,006	11,021	11,028	11,049	11,024	11,000	11,058	11,029
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.05	22.01	22.01	22.12	22.01	22.01	22.04	22.06	22.10	22.05	22.00	22.12	22.06
7	Coal Consumed [from PCM (000s tons)]		4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,861	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(125,337)	(127,416)	(126,123)	(129,658)	(129,028)	(128,114)	(123,932)	(129,790)	(125,651)	(127,762)	(128,100)	(128,628)	(129,665)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2
19	Fuel Purchased	-	133.3	197.7	220.4	207.2	218.4	227.1	237.6	236.2	237.3	233.6	245.8	243.1	248.8	250.6	257.2	262.2
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(206.9)	(216.1)	(223.9)	(236.4)	(236.3)	(236.5)	(232.4)	(245.5)	(241.6)	(248.3)	(250.2)	(255.6)	(261.4)
22	EB	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
1	**I. Sales (TWH)**																			
2																				
3	Rural	2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																				
5	Large Industrial	0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																				
7	Century	-	-	-	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
8																				
9	Alcan	-	-	-	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
10																				
11	Market	1.16	0.71	-	1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
12																				
13	Total Sales	4.53	1.80	-	8.28	12.29	12.49	11.58	11.80	11.70	12.02	11.96	11.89	11.49	12.02	11.65	11.83	11.87	11.92	12.00
14																				

Pro Forr

Decemb '07

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:		4/30/2008	
II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)																			
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FAC ($/ MWH)				5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
PPA ($/ MWH)				(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
Environmental Surcharge Adjustment ($/ MWH)																			
Rural				0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
Large Industrial				0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
Smelters				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
Rural																			
Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37
Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40
Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
Net	-	-		-	0.16	0.53	0.89	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.01	51.35	56.65	58.38	60.71	62.19	63.81	65.08	66.67	68.15	69.54	71.00	72.71
TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.01	51.35	56.65	58.38	60.71	62.19	63.81	65.08	66.67	68.15	69.54	71.00	72.71
Large Industrial																			
Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
Net	-	-		-	0.16	0.53	0.89	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	31.40	45.77	51.08	52.83	55.19	56.70	58.33	59.61	61.22	62.75	64.12	65.59	67.32
TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	31.40	45.77	51.08	52.83	55.19	56.70	58.33	59.61	61.22	62.75	64.12	65.59	67.32

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	(1.09)	(1.12)		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
75	GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76																				
77	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
78	Environmental Surcharge				0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
81	Net				-	0.16	0.53	0.89	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.28	49.62	54.91	56.64	58.97	60.46	62.07	63.34	64.93	66.42	67.80	69.26	70.97
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.28	49.62	54.91	56.64	58.97	60.46	62.07	63.34	64.93	66.42	67.80	69.26	70.97
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
89	TIER Adjustment	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
91	FAC				5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
92	PPA	-	-		(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Environmental Surcharge				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Surcharge 1	-	-		0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Surcharge 2				1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	52.51	59.65	60.56	61.79	64.01	64.99	66.46	68.90	70.47	73.98	75.55	79.03	81.33
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	47.04	56.45	58.70	60.10	62.31	63.42	64.85	66.91	68.38	71.11	72.55	75.19	77.20
102																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			*4/30/2008*	
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	91.7	133.2	150.2	157.8	167.7	175.3	183.7	191.0	199.8	208.5	217.0	225.8	235.7
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	34.6	53.3	61.3	65.2	70.0	73.9	78.0	81.8	86.1	90.3	94.6	99.1	104.0
108	Smelters	-	-	-	171.7	257.7	277.7	-	-	-	-	-	-	-	-	-	-	-	-	-
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	414.9	479.3	475.1	499.2	507.6	505.1	483.0	531.4	510.3	542.3	549.3	571.3	586.8
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	7.8	10.934	14.1	17.6	20.8	24.0	25.7	28.8	30.8	33.9	36.7	40.1
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	548.6	675.2	699.4	737.6	754.5	767.6	762.2	822.7	818.7	864.8	887.3	925.3	958.4
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	214.3	224.7	233.4	244.6	242.3	244.0	241.4	252.6	251.7	256.7	257.9	265.4	270.4
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	7.2	8.9	8.2	8.3	8.3	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
122	Carbon Tax				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Carbon Allowance Cost				-	-	-	-	91.2	103.2	118.7	131.9	144.0	151.8	172.1	179.1	195.6	209.6	222.5	238.1
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(5.6)	(1.6)	(1.9)	(3.1)	(1.1)	(5.0)	1.9	(4.2)	0.4	(2.9)	0.3	(2.9)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	406.7	502.3	532.2	558.7	583.4	597.4	621.8	647.0	665.3	689.4	715.3	739.3	766.8
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	173.0	167.2	178.9	171.1	170.2	140.4	175.7	153.4	175.4	172.0	186.0	191.6
136																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
137																				
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	173.0	167.2	178.9	171.1	170.2	140.4	175.7	153.4	175.4	172.0	186.0	191.6
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	47.2	11.9	18.9	85.7	119.1	131.6	141.1	133.4	132.0	100.0	129.5	105.9	129.8	124.2	138.6	142.3
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	Post-Finance Cash Flow	42.0	(3.5)	-	8.1	(46.5)	(39.5)	27.3	60.7	73.2	82.7	75.0	73.6	41.6	71.1	47.5	71.4	65.8	80.2	83.9
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
167	Net Before Transition Reserve			25.1	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
168																				
169	Ending Cash Balances (Incl. Transition	138.4	134.9	160.0	173.6	139.7	119.3	181.5	255.5	328.7	411.4	486.4	560.0	601.6	672.7	720.2	791.6	857.3	937.5	1,021.4
170	Reserve)																			

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
171	**IV. Income Statement (M$)**																			
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.5	87.1	88.8	94.1	133.2	150.2	157.8	167.7	175.3	183.7	191.0	199.8	208.5	217.0	225.8	235.7
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	35.5	53.3	61.3	65.2	70.0	73.9	78.0	81.8	86.1	90.3	94.6	99.1	104.0
176	Smelters	-	-	-	170.6	254.9	275.0	-	-	-	-	-	-	-	-	-	-	-	-	-
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	414.9	479.3	475.1	499.2	507.6	505.1	483.0	531.4	510.3	542.3	549.3	571.3	586.8
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
181	*WKEC Lease (Net)*	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	7.767	10.934	14.068	17.609	20.818	23.969	25.748	28.792	30.823	33.879	36.693	40.125
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	551.4	674.7	698.9	737.1	753.9	767.0	761.6	822.1	818.2	864.2	886.7	924.7	957.8
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
189	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
190	Carbon Allowance Cost			-	-	-	-	-	91.2	103.2	118.7	131.9	144.0	151.8	172.1	179.1	195.6	209.6	222.5	238.1
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
192	*Fixed Production O&M*	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	486.2	592.9	614.1	644.8	672.6	685.2	726.2	745.8	769.1	789.8	819.3	835.7	870.3
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	100.0	95.1	84.8	92.3	81.3	81.8	35.4	76.4	49.1	74.4	67.4	89.0	87.5

Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
															Transaction Closing Date:			4/30/2008	
210																			
211 **V. Balance Sheet (M$)**																			
212																			
213 Assets																			
214 Property																			
215 Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216 Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217 Depreciation & Amortization	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218 Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219 Current																			
220 Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221 General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	140.6	212.9	284.3	365.1	438.1	509.7	549.1	618.0	663.1	732.0	795.3	872.8	953.9
222 Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223 Economic Reserve	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
224 Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	45.5	55.6	57.3	60.3	61.4	62.2	61.5	66.4	65.8	69.5	71.1	74.0	76.5
225 Regulatory Asset	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
226 *Fuel Stock & Related*	-	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0
227 Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228 Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229 Credits																			
230 AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231 Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232 Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233 Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234 LEM Settlement Note/Marketing Paymer	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235 Total Assets	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,757.7	1,836.3	1,923.7	1,999.3	2,073.8	2,103.8	2,173.4	2,216.0	2,283.3	2,344.7	2,425.5	2,507.3
236																			
237 Liabilities & Equities																			
238 Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	516.6	611.8	696.6	788.9	870.2	952.0	987.4	1,063.8	1,112.8	1,187.2	1,254.6	1,343.6	1,431.1
239 Long-Term Debt																			
240 Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241 Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242 Total Long-Term Debt	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243 Current & Accrued Liabilities																			
244 Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	58.3	73.7	76.9	81.5	85.4	87.2	91.2	94.0	97.4	100.4	104.7	107.1	112.1
245 Regulatory Liability				1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
246 Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247 Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
248 Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249 Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250 Deferred TIER Rebate Payable				1.7	5.8	9.9	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
251 WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252 Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253 Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254 Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,757.7	1,836.3	1,923.7	1,999.3	2,073.8	2,103.8	2,173.4	2,216.0	2,283.3	2,344.7	2,425.5	2,507.3
255																			

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	6.0	10.1	1.8	2.9	1.1	0.8	(0.7)	4.9	(0.6)	3.7	1.6	2.9	2.5
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	0.8	(15.4)	(3.1)	(4.6)	(4.0)	(1.8)	(4.1)	(2.8)	(3.4)	(3.0)	(4.3)	(2.4)	(5.1)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(5.6)	(1.6)	(1.9)	(3.1)	(1.1)	(5.0)	1.9	(4.2)	0.4	(2.9)	0.3	(2.9)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	181.5	255.4	328.7	411.4	486.4	560.0	601.6	672.7	720.2	791.6	857.3	937.5
272	*Ending*	138.4	134.9	160.0	173.6	139.7	119.3	181.5	255.4	328.7	411.4	486.4	560.0	601.6	672.7	720.2	791.6	857.3	937.5	1,021.3
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	100.0	95.1	84.8	92.3	81.3	81.8	35.4	76.4	49.1	74.4	67.4	89.0	87.5
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	*Plus: Imputed Rate Increase in 2010*				-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
282	Total				40.7	60.5	59.8	144.8	139.2	128.1	134.6	122.7	122.3	74.8	114.7	86.3	110.5	102.2	122.6	119.5
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	159.3	154.3	143.8	150.9	139.7	140.1	93.4	134.2	106.6	131.8	124.6	146.1	144.2
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				*31.1*	*46.2*	*45.5*	*44.8*	*44.1*	*43.3*	*42.3*	*41.4*	*40.5*	*39.4*	*38.4*	*37.2*	*36.1*	*34.8*	*33.6*	*32.0*
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	2.69	2.61	2.44	2.57	2.39	2.40	1.61	2.32	1.85	2.30	2.18	2.56	2.54
291																				
292	Conventional TIER																			
293	Earnings				*10.6*	*15.8*	*13.3*	*100.0*	*95.1*	*84.8*	*92.3*	*81.3*	*81.8*	35.4	76.4	49.1	74.4	67.4	89.0	87.5
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	144.8	139.2	128.7	135.2	123.4	123.1	75.6	115.5	87.1	111.3	103.1	123.5	120.4
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	159.3	154.3	144.4	151.6	140.4	140.8	94.2	134.9	107.5	132.6	125.5	147.0	145.2
299	*Divided by*																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	2.69	2.61	2.45	2.58	2.40	2.42	1.62	2.33	1.87	2.31	2.20	2.58	2.56
305																				

	Calendar Year	**2007**	**2008H1**	**Transaction**	**2008 H2**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
306	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
307	Cash Available for Debt Service																			
308	Receipts less Disbursements				84.6	88.0	77.5	141.9	173.0	167.2	178.9	171.1	170.2	140.4	175.7	153.4	175.4	172.0	186.0	191.6
309	Economic Reserve				5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
310	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
311	Net				90.2	100.5	96.6	176.8	186.2	167.2	178.6	170.7	169.8	140.0	175.2	152.9	174.9	171.5	185.5	191.0
312	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
313	Total				99.1	113.8	110.5	191.3	201.3	182.9	194.9	187.7	187.6	158.6	194.6	173.3	196.3	193.9	209.0	215.7
314	Divided by																			
315	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
316	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
317	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
318	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
319																				
320	*DSCR*				2.06	1.59	1.53	2.62	2.74	2.47	2.61	2.49	2.46	2.06	2.50	2.20	2.46	2.40	2.55	2.60
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	150.4	218.5	292.1	370.1	448.9	523.2	580.8	637.1	696.4	755.9	824.4	897.4	979.4
324	Line of Credit				66.9	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
325	Total	117.5	136.7	147.5	233.8	256.6	229.5	250.4	318.5	392.1	470.1	548.9	623.2	680.8	737.1	796.4	855.9	924.4	997.4	1,079.4
326	Divided by																			
327	Total Operating Expense																			
328	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
330	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.8	8.9	8.9
331	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
332	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
333	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
334	APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
335	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
336	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
337	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
338	Total	182.8	69.2	-	293.6	439.0	450.9	444.4	458.4	466.9	481.9	495.0	493.9	513.0	510.8	525.8	528.7	542.7	544.7	562.3
339																				
340	*Days Cash on Hand (including Line o.*	234.5	721.0		290.6	213.4	185.8	205.6	253.5	306.5	356.0	404.8	460.5	484.4	526.7	552.8	590.8	621.7	668.3	700.7
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		207.4	130.2	104.8	123.5	173.9	228.3	280.3	331.0	386.6	413.3	455.2	483.4	521.8	554.4	601.3	635.8
342																				

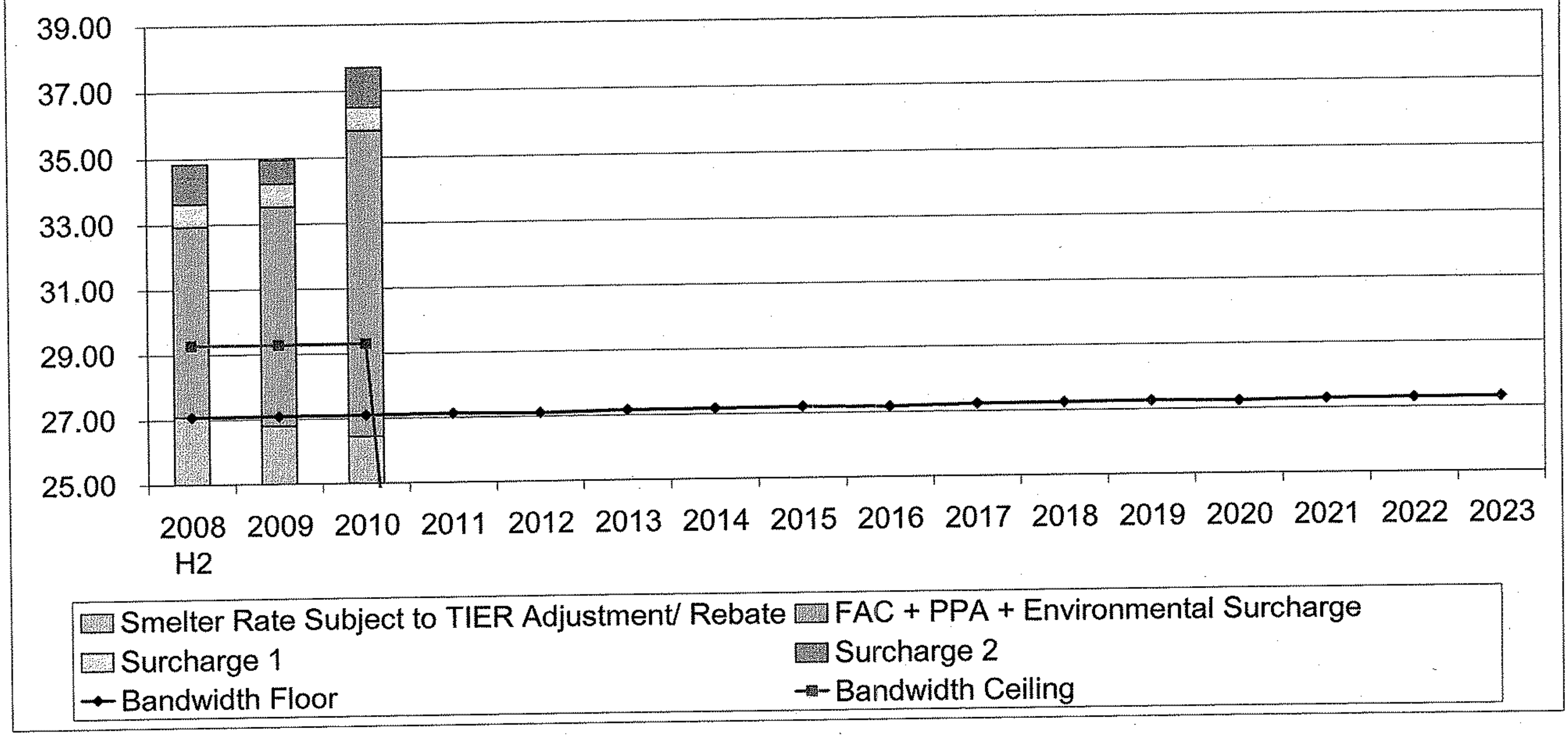
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	Blended Interest Cost		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	Accretion Rate		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	Beginning Principal		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	859.1	851.2	839.0	826.0	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

Smelter Rate Structure

December 2007

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 Smelter Sales																
2 Century	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Alcan	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Total Energy (TWh)	4.898	7.297	7.297	-	-	-	-	-	-	-	-	-	-	-	-	-
5 Total Demand (GW)	6.847	10.200	10.200	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 Smelter Rate ($/ MWh)																
9 Large Industrial Rate																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
13 Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
17 Less: Regulatory Account Charge	-	-	-	-	-	0.21	0.21	0.20	-	-	-	-	-	-	-	(0.00)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	30.51	30.53	30.55	30.56	30.58	30.61	30.62	30.63	30.65	30.69	30.68	30.69	30.71
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.11	27.09	27.15	27.16	27.18	27.16	27.21	27.23	27.24	27.22	27.27	27.28	27.29
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.36	27.34	27.40	27.41	27.43	27.41	27.46	27.48	27.49	27.47	27.52	27.53	27.54
23 Plus TIER Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Plus Surcharge 1	0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Plus Surcharge 2	1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-

Smelter Price and Bandwidth



Smelter Rate Structure

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	129.6	186.6	211.5	223.1	237.8	249.2	261.7	272.9	286.0	298.8	311.6	324.9	339.7
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	75.8	115.1	102.9	456.6	501.5	487.4	514.0	516.1	517.8	499.9	549.3	532.2	565.4	575.1	599.9	618.1
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	586.3	688.0	698.9	737.1	753.9	767.0	761.6	822.1	818.2	864.2	886.7	924.7	957.8
Total Expenses	315.2	473.3	486.4	486.2	592.9	614.1	644.8	672.6	685.2	726.2	745.8	769.1	789.8	819.3	835.7	870.3
Net Margin Before TIER Adjustment	12.3	21.7	23.3	100.0	95.1	84.8	92.3	81.3	81.8	35.4	76.4	49.1	74.4	67.4	89.0	87.5
Interest + Margin	52.4	81.2	82.7	159.3	154.3	143.8	150.9	139.7	140.1	93.4	134.2	106.6	131.8	124.6	146.1	144.2
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	2.69	2.61	2.44	2.57	2.39	2.40	1.61	2.32	1.85	2.30	2.18	2.56	2.54
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	(85.8)	(80.9)	(70.7)	(78.2)	(67.3)	(67.9)	(21.5)	(62.5)	(35.2)	(60.6)	(53.7)	(75.3)	(73.9)
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Offset to Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Adjustments	(1.0)	(1.5)	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	(85.8)	(80.9)	(70.7)	(78.2)	(67.3)	(67.9)	(21.5)	(62.5)	(35.2)	(60.6)	(53.7)	(75.3)	(73.9)
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>Rebate to Members/Smelters ($/MWh)</u>																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
<u>TIER Adjustment Charge to Smelters ($/MWh)</u>	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Member Rates Cash Method

December 2007

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37
10	Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
14	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
16	Env. Surcharge	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
20	Net	-	(0.01)	(0.02)	(0.04)	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
21	Effective Rate	36.07	36.11	36.09	36.07	51.35	56.65	58.38	60.71	62.19	63.81	65.08	66.67	68.15	69.54	71.00	72.71
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
26	Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
30	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
32	Env. Surcharge	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
36	Net	-	0.02	0.06	0.09	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
37	Effective Rate	30.58	30.48	30.54	30.59	45.77	51.08	52.83	55.19	56.70	58.33	59.61	61.22	62.75	64.12	65.59	67.32
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
43	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
45	Env. Surcharge	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
49	Net	-	0.00	0.00	0.00	15.24	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
50	Effective Rate	34.44	34.40	34.39	34.39	49.62	54.91	56.64	58.97	60.46	62.07	63.34	64.93	66.42	67.80	69.26	70.97
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	-	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

December 2007

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
EXPENSE DEFERRAL METHOD																
Income Statement (Change in Regulatory Account)																
1. Deferral																
Power Purchase Expense																
Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
Credit	-	(0.17)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.26	(0.17)	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
2. Recognition of Prior Year Balance (Set to Start in 2013)																
Credit Member Revenue (Charge to Members)						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
Debit Power Purchase Expense						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
Net Income	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
Balance Sheet																
Assets																
Cash						(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
Regulatory Asset	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	-	-	-	-	-	(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
Liabilities & Equity																
Equity	(1.3)	(1.1)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
Regulatory Liability	1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
Total	-	-	-	-	-	(0.8)	(1.6)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.3	11.5	11.5	11.8	11.7	11.7	11.3	11.8	11.4	11.6	11.6	11.7	11.8
2	**Sales (TWh)**	8.3	12.3	12.5	11.6	11.8	11.7	12.0	12.0	11.9	11.5	12.0	11.6	11.8	11.9	11.9	12.0
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold)	16.62	16.56	17.77	18.48	18.86	19.69	20.25	20.26	20.44	20.91	20.99	21.48	21.66	21.71	22.13	22.46
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	6.88	8.58	7.83	7.94	7.95	7.94	8.31	8.12	8.35	8.29	8.44	8.57	8.57
13																	
14	Total Costs for Passthrough ($/ MWh Sold)	1.21	1.80	1.38	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	30.34	125.45	137.78	155.53	182.55	194.64	201.16	224.96	230.59	249.79	266.46	280.00	298.56
20																	
21	Total Costs for Passthrough ($/ MWh Sold)	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/M	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
29	Environmental Surcharge	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
30	**Total**	6.39	6.69	9.73	10.39	18.78	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
33	Environmental Surcharge	0.49	0.85	2.68	2.62	10.64	11.78	12.94	15.26	16.36	17.52	18.71	19.80	21.12	22.45	23.49	24.88
34	**Total**	6.39	6.69	9.73	10.39	18.78	20.75	22.48	24.80	26.09	27.71	28.98	30.57	32.06	33.44	34.90	36.62
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
37	PPA	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Environmental Surcharge	0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
39	**Total**	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-

UW Transaction

	($M)	2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	1. Cash Payment/ Credit Escrow Draws	-	-	301.5	-
2	2. WKE Residual Value Obligation				
3	WKE Gen. Capex - Cum.				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	3. LG&E Rental Income Advance				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	4. Fuel & Other Inventories	-	-	55.0	-
20	5. Cancellation of Settlement Prom. Note	-	-	16.0	-
21	6. Coleman Scrubber Completion	-	-	97.5	-
22	7. LG&E Emissions Allowance	-	-	10.9	-
23	8. Expense Unamortized Mktg Payment/ Settlement Note			(15.7)	
24	9. Assurances Agreement	-	-	4.3	-
25					
26	Total Residual Value Obligation	154.1	161.8	161.8	-
27	Cancellation of RV Obligation				
28	Reclassification as Equity	-	-	161.8	-
29					
30	Net WKE Obligation	154.1	161.8	-	-
31					

UW Transaction

($M)

			2007	2008H1	Transaction	2008 H2
	Unwind Allocation			0		0
	Pre-Transaction Allocation		-	-	-	0.669
	Transaction Index		1.000	0.331	-	-
32			-	-	1.000	-
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction					
35	Transaction Proceeds				134.9	
36	Smelter Payment (Assurances Agreement)				301.5	
37	Consent Fee to Lease-Equity Parties				(4.3)	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				-	
41	Income Tax				(0.3)	
42	Net Transaction Cash				(1.1)	
43	Debt Restructuring:				295.9	
44	Debt Reduction (Net)					
45	Underwriting Costs				(186.2)	
46	Bond Insurance	1.75%			(4.6)	
47	ARVP Defeasance Premium	0.80%			(5.0)	
48	Total				-	
49	Restricted Cash Balances:				(195.8)	
50	Transition Reserve					
51	Economic Reserve				(35.0)	
52	Unrestricted Cash Balances Post-Transaction				(75.0)	
53					125.0	
54	**C. Debt Restructuring:**					
55	Beginning Balance - GAAP					
56	Cancellation of Settlement Prom. Note				1,051.1	
57	Capitalize Accrued Interest on RUS New Note				(16.0)	
58	Step-Up RUS New Note to Stated Basis:				7.2	
59	GAAP RUS New Note					
60	Ending Balance					
61	Accrued Interest				791.4	
62	Total				7.2	
63	Stated RUS New Note				798.6	
64	Ending Balance					
65	Accrued Interest				794.7	
66	Total				7.0	
67	Step-Up				801.7	
68	Beginning Balance - Stated				3.1	
69	Cash Flow:				1,045.3	
70	Prepay RUS New Note					
71	Defease ARVP				(449.7)	
72	Issue Capital Markets Debt				-	
73	Net				263.5	
74	Ending Balance - Stated				(186.2)	
75	Step-Down Remaining RUS New Note to GAAP Basis:				859.2	
76	Ending Balance - GAAP				(1.3)	
77					857.8	

UW Transaction

	($M)		2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				
121						
122	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
123						
124	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
125						
126	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production-Fixed

December 2007

Production - Fixed

	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Total Real		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	Gross Generation		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	**Depreciation**																				
70																					
71	Additional Book Depreciation																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	HMP&L Station Two																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	Environmental																				
89	*Prior year environmental*						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	Other																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	*0.04*	*0.03*	*0.01*	*0.01*	*0.02*	*0.02*	*0.03*	*0.03*	*0.03*	*0.03*	*0.03*	*0.03*
101																					
102	Book Depreciation & Amortization																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	*Blended Depreciation Adj.*		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

December 2007

	($M)	2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																		
2	Beginning Balance		-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest		-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal		(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service		(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																			
9	Fixed/ Insured (Tranche 2)																		
10	Beginning Balance		-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon		0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)		0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest		-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal		(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service		(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																			
17	RUS -- GAAP																		
18	Beginning Balance		791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon		0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)		0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest		-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest		440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service		440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																			
25	Variable																		
26	Beginning Balance		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon		0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																			
33	PCB																		
34	Beginning Balance		142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon		0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest		-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal		-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service		-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																			
41	ARVP																		
42	Beginning Balance		101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion		-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																			
51	Total																		
52	Beginning Balance		1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion		-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal		177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest		-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service		177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance		857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																			

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
59	Supporting Schedules																			
60	Amortization of Financing Costs																			
61	Fixed/ Insured (Tranche 1)																			
62	Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63	BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64	YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65	Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67	EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71	BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72	YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73	Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74	Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75	EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																				
77	Variable																			
78	Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79	BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80	YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81	*Principal Amort.*			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82	Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83	EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																				
85																				
86	Amortization of Financing Costs																			
87	Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88	*Amortization*			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89	Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																				
91	Interest Expense																			
92	Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93	ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94	Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95	AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96	Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97	Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

December 2007

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	*Balance Sheet*	*193.7*	*195.4*	*200.4*	*201.5*	*209.8*	*218.4*	*226.7*	*235.7*	*245.2*	*255.4*	*266.4*	*278.1*	*290.7*	*304.2*	*318.6*	*334.0*	*350.6*	*368.3*
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	Cash Flow (Investment and Liability)	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	<u>Sale-Leaseback - LeaseCo.</u>																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

December 2007

		2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	($M)																			
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	*Defeasance Income*	*64.5*	*8.4*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	*Additions*	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	Non-Incremental	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476)	0	0
				185,791,428		

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
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ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

	Electricity Sales, Purchases, and Production	Source:	005/ Othe	2006	2007	2008H1	Transactio 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Sales																						
2	Rural																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109	3.142	3.142	-	-	-	-	-	-	-	-	-	-	-	-	-
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	366	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.16						2.789	4.155	4.155	-	-	-	-	-	-	-	-	-	-	-	-	-
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484	484	484	-	-	-	-	-	-	-	-	-	-	-	-	-
18																							
19	Offsystem (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		1.93	1.16	0.71		1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
20																							
21	Purchases & Production																						
22	Purchases (TWh)																						
23	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.00	-	0.00	-	-	-	0.01	-	0.00	-	0.00	0.00	-
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		8.07	11.80	12.10	11.31	11.53	11.47	11.80	11.74	11.67	11.26	11.80	11.43	11.61	11.65	11.70	11.79
26	Loss Rate (%)	file: annual output - 2-5-08 - No Smelters after 2010.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	Fuel Consumption (MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						89.9	131.5	134.0	125.3	127.4	126.1	129.7	129.0	128.1	123.9	129.8	125.7	127.8	128.1	128.6	129.7
29																							
30	Startup Costs (M$)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4.36	6.54	6.84	7.06	6.35	6.39	6.96	6.10	6.62	7.78	6.80	8.60	7.90	7.35	8.13	8.18
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		14,032	18,797	19,882	18,354	19,098	18,060	19,229	18,959	19,263	17,802	19,391	18,577	19,090	18,763	19,247	18,922
35	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125
36	NOX																						
37	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,932	13,610	13,606	12,599	12,680	12,861	12,837	12,932	12,634	12,608	12,823	12,600	12,824	12,840	12,672	13,095
38	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,651	11,072	11,072	11,072	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		67.8347	77.90	200.00		47.55	53.53	53.88	43.50	7.91	55.27	10.06	11.23	12.34	60.53	14.58	70.29	16.84	66.23	60.74	20.20
46	Variable Production ($/ MWh sales)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	2.27		2.27	2.45	2.60	2.84	3.06	3.14	3.18	3.54	3.64	3.75	3.81	3.90	4.01	4.19	4.22	4.38
47	SO2 Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	778		778	853	861	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 2-5-08 - No Smelters after 2010.xls	100%					4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,861	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
51																							
52	**Sales Rates & Related**																						
53																							
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	Market ($/ MWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		43.30	42.91	37.82		48.40	51.34	49.47	52.61	59.65	60.56	61.79	64.01	64.99	66.46	68.90	70.47	73.98	75.55	79.03	81.33
57																							
58	Rural																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	Smelters																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (Alcan) and 1.1.19 (Century)						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	40.39	42.51	43.22	43.69	46.46	46.71	50.93	47.90	51.41	51.12	53.51	52.89	55.16
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	-	-	-	-	-	-	-	-	-	-	-	-	-
70	*Surcharge 2 ($/MWh)*	*Smelter Retail Agreements, Sections 4.11 (b) and (c)*	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	-	-	-	-	-	-	-	-	-	-	-	-	-
73																							
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback ransaction		3.68	3.68000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	-	-	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	-	-	-	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84	*Allocation of Revenues on '*																						
85	Total																						
86	NOx + SO3	file: annual output - 2-5-08 - No Smelters after 2010.xls																					
87	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.99	3.30	3.74	3.58	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	6.72	7.41	7.81	7.90	8.67
89	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
91	Net Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
92	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
93	**Allowed in ES**																						
94	NOx + SO3	file: annual output - 2-5-08 - No Smelters after 2010.xls																					
95	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	8.72	7.41	7.81	7.90	8.67
97	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
99	Net Allowance Costs in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
100	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
101																							
102	Smelter Rate Structure																						
103	*Bandwidth*	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	*Variable*	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	*Variable*	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Lev				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.58	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances		-	-	-	195.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	Straightline amortization of RUS and PCB restructuring costs				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.15																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.66	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.19	11.41	12.77	-	25.85															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	Termination Agreement		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	*Net Conforming Receipts*	Big Rivers' estimate		-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.46	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	Lease Related & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	*Green*	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	NOx ongoing	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (Includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	*Adjustment (8/2007)*			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "Incremental" items moved to O&M																						
221	W-1 stack repair	*file: Fin Model inputs BREC Nov-07 w outage shift.xls*						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	*Upgrades, Phase I (Real Basis)*																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	Property Tax	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	*2004 actual escalated @ 3%*						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property (Nominal Basis)	Unwind spreadsheet – 8-29-07_Rev1.xls						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.60	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	Property Tax			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	Generation			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	*Adjustment for Station 2 (Real Basis 2006)*	*file: Fin Model inputs BREC Nov-07 w outage shift.xls*						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	Per Crockett Memo dated 11/12/07		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.48	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.83	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.26	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	*NOx Removal Equipment Capital*	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	Cimn FGD Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filter drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	*R-CT reliability study & upgrades*	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Wilson super heater tubes replacment	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	Phase I	*Per Crockett Memo dated 11/12/07*		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-			3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	*Phase I*			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.65	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	***Other Disbursements (M$)***																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	Environmental	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	*LEM Settlement Note*	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-																	
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	-
307	Green River Coal Settlement	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson	file: annual output - 2-5-08 - No Smelters after 2010 xls		-			-	0.19	0.31	0.31	0.31	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.11)	(34.89)	(13.32)	-	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	Amortization of RUS/PCB Charges	Straightline amortization of RUS and PCB restructuring costs					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.28%																				
321																							
322	*Inflation*	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Herrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements, Section 1.1.119	35.00		0																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	*1,714.8*	*1,731.2*	*1,760.4*	*1,780.2*																	
338	Construction in Progress	Historic and Projected Balance Sheet	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	826.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	*Historic Balance Sheet*	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	Credit Escrow	Economic Reserve	-	-	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	*0.7*	*0.8*	*0.8*	*0.8*																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	AMBAC/Credit Suisse July '98	Historic and Projected Balance Sheet	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	*Deferred Tax*	*Historic Balance Sheet*	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	Total Assets																						
355																							
356	*Liabilities*																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	Long-Term Debt																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	Current & Accrued Liabilities																						

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc Included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.28	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	0.5	-	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(34.9)	(13.3)	-	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	Depreciation																						

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic		6.38	10.88	5.29																	
458	Depreciation as a *Percentage of Gross PPE*	*Historic depreication rate*		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	*Prior year*	Historic		6.00	6.77	4.96																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		25.36	25.39	8.58		26.58	9.01														
475	HMP&L Station Two	Historic		1.58	1.64	0.54		0.93	0.31														
476	Other	Historic		5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3.10						0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
480	**Income Tax Related**																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4,196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.80	0.00	0.00																	
490	Temporary Differences																						
491	*2005 Cumulative Balance of Capex not reflected* in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	5.58	5.70																
507																							
508	*Nonpatronage MWH*	Historic	1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Harrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Harrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Harrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Harrington/ Deloitte	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	7.91	8.99	10.06	11.23	12.34	13.48	14.58	15.67	16.84	18.00	19.01	20.20
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Fuel Inventory

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	*0.000*	*0.669*	*1.000*	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	*0.000*	*0.000*	*0.000*	*0.000*
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,023	11,004	11,003	11,059	11,007	11,006	11,021	11,028	11,049	11,024	11,000	11,058	11,029
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.05	22.01	22.01	22.12	22.01	22.01	22.04	22.06	22.10	22.05	22.00	22.12	22.06
7	Coal Consumed [from PCM (000s tons)]		4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,861	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(125,337)	(127,416)	(126,123)	(129,658)	(129,028)	(128,114)	(123,932)	(129,790)	(125,651)	(127,762)	(128,100)	(128,628)	(129,665)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2
19	Fuel Purchased	-	133.3	197.7	220.4	207.2	218.4	227.1	237.6	236.2	237.3	233.6	245.8	243.1	248.8	250.6	257.2	262.2
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(206.9)	(216.1)	(223.9)	(236.4)	(236.3)	(236.5)	(232.4)	(245.5)	(241.6)	(248.3)	(250.2)	(255.6)	(261.4)
22	EB	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0

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		2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Calendar Year																			
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
1	**I. Sales (TWH)**																			
2																				
3	Rural	2.40	0.76	-	1.63	2.44	2.49	2.54	2.59	2.65	2.70	2.76	2.82	2.88	2.94	3.00	3.06	3.12	3.18	3.24
4																				
5	Large Industrial	0.97	0.32	-	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
6																				
7	Century	-	-	-	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
8																				
9	Alcan	-	-	-	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
10																				
11	Market	1.16	0.71	-	1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
12																				
13	Total Sales	4.53	1.80	-	8.28	12.29	12.49	11.58	11.80	11.70	12.02	11.96	11.89	11.49	12.02	11.65	11.83	11.87	11.92	12.00
14																				

Pro Form

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
15	**II. Rates, Accrual Based ($/ MWH Sold, unless otherwise noted)**																			
16																				
17	General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
18																				
19	FAC ($/ MWH)				5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
20																				
21	PPA ($/ MWH)				(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
22																				
23	Environmental Surcharge Adjustment ($/ MWH)																			
24	Rural				0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
25	Large Industrial				0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
26	Smelters				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
27																				
28	Rural																			
29	Load Factor (%)	64.3%	60.2%		60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
30	Demand ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37
31	Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40
32																				
33	Base	36.10	37.18		37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
34	MRDA	(1.13)	(0.39)		(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
35	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
36	GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
37																				
38	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
39	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
40	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
42	Net	-	-		-	0.16	0.53	0.89	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
43																				
44	Pre TIER Rebate Total	34.96	36.79		36.07	36.28	36.64	37.01	44.57	48.84	49.83	51.17	51.63	51.89	52.74	52.94	53.68	54.15	54.71	55.59
45	TIER Related Rebate	-	-		(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Effective Rate ($/ MWH)	34.96	36.79		35.82	35.71	35.69	37.01	44.57	48.84	49.83	51.17	51.63	51.89	52.74	52.94	53.68	54.15	54.71	55.59
47																				
48	Large Industrial																			
49	Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
50	Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
51	Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
52																				
53	Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
54	Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
56	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
57	GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
58																				
59	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
60	Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
61	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
62	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
63	Net	-	-		-	0.16	0.53	0.89	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
64																				
65	Pre TIER Rebate Total	30.07	28.67		30.58	30.62	31.01	31.40	39.00	43.27	44.28	45.64	46.15	46.40	47.27	47.49	48.27	48.73	49.31	50.20
66	TIER Related Rebate	-	-		(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Effective Rate ($/ MWH)	30.07	28.67		30.36	30.14	30.19	31.40	39.00	43.27	44.28	45.64	46.15	46.40	47.27	47.49	48.27	48.73	49.31	50.20
68																				

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
69	Non-Smelter Member Blend																			
72	Base	34.64	35.50		35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
73	MRDA	*(1.09)*	*(1.12)*		(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
74	Regulatory Account Charge				-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
75	GRA	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76																				
77	FAC	-	-		5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
78	Environmental Surcharge				0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
79	Surcredit	-	-		(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
80	Economic Reserve	-	-		(2.39)	(3.58)	(5.33)	*(9.50)*	*(3.54)*	-	-	-	-	-	-	-	-	-	-	-
81	Net				-	0.16	0.53	0.89	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
82																				
83	Pre TIER Rebate Total	33.55	34.37		34.44	34.56	34.92	35.28	42.84	47.11	48.09	49.43	49.90	50.15	51.00	51.20	51.95	52.41	52.97	53.85
84	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.19	34.02	34.01	35.28	42.84	47.11	48.09	49.43	49.90	50.15	51.00	51.20	51.95	52.41	52.97	53.85
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
89	TIER Adjustment	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	Smelter Rate Subject to Price Cap	-	-		27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
91	FAC				5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
92	PPA	-	-		(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
93	Environmental Surcharge				0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
94	Surcharge 1	-	-		0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
95	Surcharge 2				1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
96	TIER Related Rebate	-	-		(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	52.51	52.37	52.20	52.64	53.80	53.69	53.68	55.70	55.79	58.50	59.08	61.62	63.02
100																				
101	Overall Blend	39.26	35.74		36.39	36.67	38.15	47.04	49.34	50.52	51.15	52.33	52.38	52.38	54.01	54.05	56.01	56.50	58.21	59.36
102																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
103	**III. Cash Flows (M$)**																			
104																				
105	Operating Receipts																			
106	Rural	83.8	28.0	-	58.9	88.0	89.8	91.7	115.7	129.5	134.7	141.4	145.6	149.4	154.8	158.7	164.2	169.0	174.0	180.2
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.5	34.6	45.4	51.9	54.7	57.9	60.1	62.1	64.9	66.8	69.5	71.9	74.5	77.6
108	Smelters	-	-	-	171.7	257.7	277.7	-	-	-	-	-	-	-	-	-	-	-	-	-
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	414.9	420.9	409.5	425.3	426.7	417.3	390.2	429.6	404.0	428.8	429.6	445.4	454.7
110	WKEC Lease	48.0	15.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
111	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
112	Smelter - Tier 3 Transmission	1.7	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
113	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
114	Cobank Patronage Capital & Other	0.5	0.2	-	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
115	Interest Earnings	6.6	2.0	-	4.6	7.4	6.0	5.1	7.8	10.562	13.5	16.7	19.7	22.5	23.9	26.6	28.2	30.8	33.1	36.0
116	Total Receipts	239.9	84.398	-	322.3	481.3	485.3	548.6	591.3	603.4	629.5	634.1	635.1	617.5	665.8	649.7	683.5	693.7	719.4	740.2
117																				
118	Operating Disbursements																			
119	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Fuel Costs	-	-	-	137.6	204.3	227.2	214.3	224.7	233.4	244.6	242.3	244.0	241.4	252.6	251.7	256.7	257.9	265.4	270.4
121	SEPA & Other Purchases	6.9	3.8	-	10.2	22.4	17.6	7.2	8.9	8.1	8.3	8.3	8.3	8.6	8.4	8.7	8.6	8.7	8.8	8.9
122	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Carbon Allowance Cost			-	-	-	-	-	11.3	11.8	16.0	17.7	18.5	14.8	23.7	19.3	24.3	27.0	28.4	32.6
124	Environmental	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
125	Fixed O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
126	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
127	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
128	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
129	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
130	Working Capital	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(0.9)	(0.9)	(1.2)	(2.4)	(0.5)	(4.3)	2.5	(3.5)	1.1	(2.2)	1.0	(2.2)
131	PCB Restructuring	-	-	-	-	-	-	-	-	2.8	-	-	-	-	-	-	-	-	3.3	-
132	Other	1.9	0.7	-	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.0)	-
133	Total Disbursements	126.3	50.0	-	237.7	393.3	407.7	406.7	427.0	441.6	456.6	469.9	472.5	485.4	499.3	506.1	518.8	533.3	545.8	562.0
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	164.3	161.8	172.8	164.2	162.6	132.1	166.5	143.5	164.7	160.5	173.6	178.2
136																				

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
137																				
138	Operating Receipts less Disbursements	113.6	34.4	-	84.6	88.0	77.5	141.9	164.3	161.8	172.8	164.2	162.6	132.1	166.5	143.5	164.7	160.5	173.6	178.2
139																				
140	Capital Expenditures																			
141	Generation	6.6	2.2	-	14.6	32.5	23.7	28.8	30.1	30.4	31.3	32.2	33.2	34.2	35.2	36.2	37.3	38.5	39.6	40.8
142	Transmission	9.6	5.2	-	6.2	9.6	9.2	4.4	5.9	0.5	0.4	0.5	1.6	2.8	3.4	3.5	3.6	3.7	3.8	3.9
143	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
144	A&G	1.3	0.4	-	0.9	1.3	1.4	1.4	1.5	1.5	1.5	1.6	1.6	1.7	1.7	1.8	1.8	1.9	2.0	2.0
145	Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
146	Other (HQ Building, IP)	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
147	Total Capital Expenditures	21.6	7.8	-	37.5	76.0	58.6	56.3	53.9	35.5	37.5	37.3	37.8	40.0	45.7	47.1	45.1	47.4	46.9	48.8
148																				
149	Income Taxes from Operations	0.9	0.1	-	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
150																				
151	Net Pre-Finance Cash Flow	91.2	26.5	-	47.2	11.9	18.9	85.7	110.4	126.3	135.0	126.6	124.5	91.7	120.4	96.0	119.1	112.6	126.1	128.9
152																				
153	Financing																			
154	Principal	12.5	13.0	-	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
155	Interest	36.7	16.9	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
156	Line of Credit	-	-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
157	Aggregate Debt Service (incl. Line	49.2	30.0	-	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4
158																				
159	Post-Finance Cash Flow	42.0	(3.5)	-	8.1	(46.5)	(39.5)	27.3	52.0	67.9	76.6	68.2	66.0	33.3	62.0	37.6	60.7	54.2	67.7	70.5
160																				
161	Unwind Transaction																			
162	Cash Proceeds			301.5																
163	Debt Reduction			(195.8)																
164	Misc. Transaction			(5.6)																
165	Net Before Member Reserves			100.1																
166	Economic Reserve			(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
167	Net Before Transition Reserve			25.1	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
168																				
169	Ending Cash Balances (Incl. Transition	138.4	134.9	160.0	173.6	139.7	119.3	181.5	246.8	314.6	391.3	459.4	525.5	558.8	620.8	658.4	719.1	773.3	841.0	911.5
170	Reserve)																			

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
171	**IV. Income Statement (M$)**																			
172																				
173	Revenues																			
174	*Rural*	83.8	28.0	-	58.5	87.1	88.8	94.1	115.7	129.5	134.7	141.4	145.6	149.4	154.8	158.7	164.2	169.0	174.0	180.2
175	Large Industrial	29.3	9.3	-	21.0	32.0	33.1	35.5	45.4	51.9	54.7	57.9	60.1	62.1	64.9	66.8	69.5	71.9	74.5	77.6
176	Smelters	-	-	-	170.6	254.9	275.0	-	-	-	-	-	-	-	-	-	-	-	-	-
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	414.9	420.9	409.5	425.3	426.7	417.3	390.2	429.6	404.0	428.8	429.6	445.4	454.7
178	Transmission	5.1	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
179	Smelter - Tier 3 Transmission	1.8	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
180	Gain on Sale of Allowances	-	-	-	14.3	18.5	(2.0)	1.7	1.0	1.4	0.7	(9.1)	(8.1)	(7.1)	(7.9)	(6.9)	(7.7)	(8.0)	(8.1)	(8.9)
181	WKEC Lease (Net)	52.3	17.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Interest Earnings	6.6	2.0	-	4.584	7.431	5.978	5.107	7.767	10.562	13.467	16.747	19.664	22.491	23.916	26.570	28.179	30.777	33.096	35.995
183	Total Revenues	243.9	85.8	-	320.2	476.6	480.7	551.4	590.8	602.9	628.9	633.6	634.6	617.0	665.3	649.1	683.0	693.2	718.8	739.6
184																				
185	Expenses																			
186	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
187	Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
188	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.7	8.8	8.9
189	*Carbon Tax*			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
190	Carbon Allowance Cost			-	-	-	-	-	11.3	11.8	16.0	17.7	18.5	14.8	23.7	19.3	24.3	27.0	28.4	32.6
191	Non-Fuel Variable Production O&M	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
192	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
193	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
194	APM, L/C, Cogen, CW & TVA Trans	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
195	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
196	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
197	Depreciation & Amortization	32.3	10.9	-	23.8	37.6	38.8	45.0	46.5	46.5	46.6	48.1	49.5	63.8	65.0	66.3	67.7	69.0	70.4	71.8
198	Income Tax	-	-	-	-	-	-	-	-	0.638	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
199	Interest Expense (Incl. Financing Fee	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
200	RUS Note & PCB Restructuring Char	-	-	-	0.1	0.1	0.1	0.1	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.5
201	Net Sale-Leaseback	(2.6)	(0.8)	-	(1.7)	(2.4)	(2.5)	(2.5)	(2.5)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
202	Other - Net	(6.3)	(2.3)	-	(0.6)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)
203	Total Expenses	206.3	76.9	-	315.2	473.3	486.4	486.2	513.0	522.7	542.1	558.5	559.6	589.2	597.4	609.3	618.6	636.6	641.6	664.8
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	(75.0)	5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	10.6	15.8	13.3	100.0	91.1	80.1	86.8	75.1	75.0	27.8	67.9	39.9	64.4	56.5	77.3	74.8

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	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
210																				
211	**V. Balance Sheet (M$)**																			
212																				
213	Assets																			
214	Property																			
215	Total Utility Plant in Service	1,760.4	1,780.2	1,877.7	1,923.7	2,000.5	2,060.0	2,117.1	2,171.8	2,208.2	2,246.5	2,284.6	2,323.2	2,364.1	2,410.6	2,458.6	2,504.5	2,552.8	2,600.5	2,650.1
216	Construction in Progress	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
217	*Depreciation & Amortization*	858.9	869.8	869.8	893.6	931.2	969.9	1,015.0	1,061.4	1,107.9	1,154.5	1,202.5	1,252.1	1,315.8	1,380.9	1,447.2	1,514.9	1,583.9	1,654.3	1,726.1
218	Other Property	197.3	199.2	199.2	204.4	205.9	214.6	223.6	232.3	241.6	251.5	262.1	273.4	285.4	298.4	312.2	326.9	342.7	359.6	377.7
219	Current																			
220	Cash General Funds & Special Deposits	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
221	General Cash Balance	138.4	134.9	125.0	137.6	102.1	80.2	140.6	204.2	270.2	345.0	411.2	475.1	506.3	566.1	601.3	659.6	711.2	776.3	844.0
222	Transition Reserve	-	-	35.0	36.0	37.5	39.1	40.8	42.6	44.4	46.3	48.3	50.3	52.5	54.7	57.1	59.5	62.1	64.7	67.5
223	Economic Reserve	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	39.3	39.1	39.6	45.5	48.6	49.4	51.3	51.4	51.2	49.5	53.4	51.9	54.6	55.2	57.1	58.6
225	Regulatory Asset	-	-	-	-	-	-	-	-	-	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
226	Fuel Stock & Related	-	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0
227	Materials and Supplies Other	0.8	0.8	0.8	0.9	0.9	0.9	0.9	1.0	1.0	1.0	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3
228	Other Current Assets	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7
229	Credits																			
230	AMBAC/Credit Suisse July '98	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
231	Deferred Tax	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
232	Deferred Debt Debits/PCB Refunding 10	0.5	0.3	11.7	11.5	11.1	10.7	10.3	9.8	12.0	11.4	10.7	10.1	9.4	8.7	8.0	7.3	6.5	8.9	8.1
233	Other Deferred Assets	-	-	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
234	LEM Settlement Note/Marketing Paymer	16.1	15.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
235	Total Assets	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,742.0	1,814.3	1,894.6	1,962.4	2,028.3	2,049.1	2,108.6	2,140.3	2,195.9	2,244.7	2,312.1	2,379.6
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	387.5	403.3	416.6	516.6	607.8	687.9	774.8	849.9	924.9	952.7	1,020.6	1,060.5	1,124.8	1,181.4	1,258.6	1,333.4
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
241	Sale-Leaseback Obligation	183.9	186.2	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
242	*Total Long-Term Debt*	1,246.0	1,237.3	1,044.1	1,040.8	1,030.1	1,026.0	1,021.5	1,015.9	1,010.1	1,004.0	997.8	991.3	984.6	977.7	970.5	963.1	955.4	947.6	939.6
243	Current & Accrued Liabilities																			
244	Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	58.3	62.1	63.5	66.5	68.8	68.9	71.2	72.4	74.1	75.4	78.1	78.7	82.2
245	Regulatory Liability				1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
246	Taxes Accrued	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3
247	Economic Reserve Deferred Income	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
248	Interest Accrued	7.8	7.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
249	Other Accrued Liabilities	6.2	6.3	6.3	6.4	6.6	6.8	7.0	7.2	7.4	7.7	7.9	8.1	8.4	8.6	8.9	9.1	9.4	9.7	10.0
250	Deferred TIER Rebate Payable				1.7	5.8	9.9	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7	6.7
251	WKEC Lease (Resid. Value Obligation)	154.1	161.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
252	Sale-Leaseback Gain	53.5	52.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
253	Other Deferred Credits & Century Reacti	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254	Total Liabilities & Equity	1,300.0	1,306.8	1,567.0	1,617.6	1,614.8	1,612.2	1,668.1	1,742.0	1,814.3	1,894.6	1,962.4	2,028.3	2,049.1	2,108.6	2,140.3	2,195.9	2,244.7	2,312.1	2,379.6
255																				

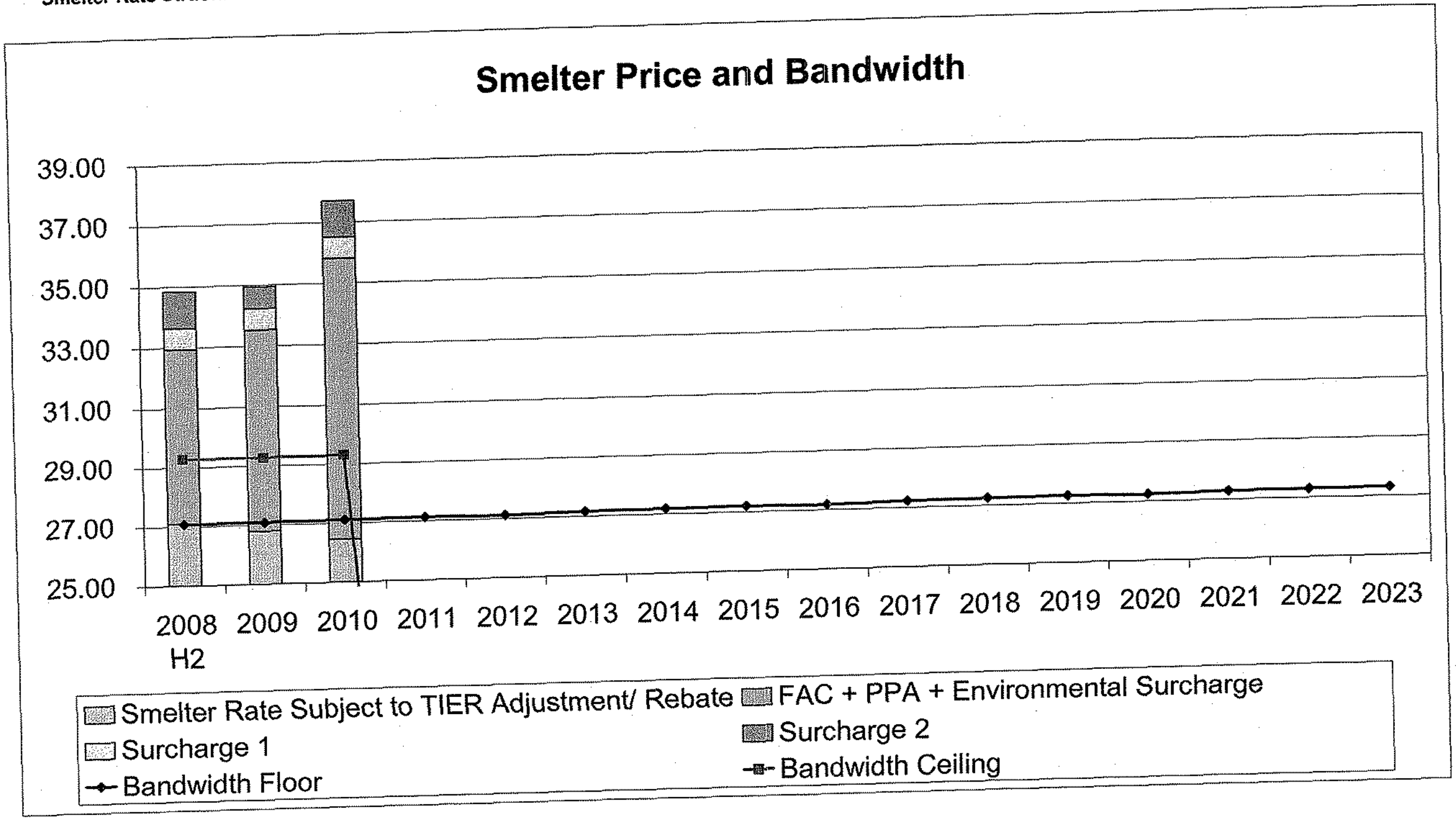
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																	Transaction Closing Date:		4/30/2008	
256	Change in Working Capital																			
257	Other Property	6.6	1.8	-	5.2	1.5	8.6	9.0	8.7	9.3	9.9	10.6	11.3	12.1	12.9	13.8	14.8	15.8	16.9	18.1
258	Accounts Receivable	0.3	-	-	21.6	(0.2)	0.5	6.0	3.1	0.8	1.9	0.1	(0.2)	(1.7)	3.9	(1.6)	2.7	0.6	1.9	1.5
259	Materials, Supplies & Other	0.0	0.0	-	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
260	Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
261	Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	0.8	(3.8)	(1.4)	(2.9)	(2.3)	(0.1)	(2.4)	(1.2)	(1.7)	(1.3)	(2.6)	(0.7)	(3.4)
262	Taxes Accrued	(0.0)	(0.0)	-	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
263	Other Accruals	(0.2)	(0.1)	-	(0.1)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
264	Investment - Special Deposit (B/S)	(6.2)	(2.2)	-	(4.5)	(1.1)	(8.3)	(8.7)	(8.3)	(8.9)	(9.5)	(10.2)	(11.0)	(11.7)	(12.6)	(13.5)	(14.4)	(15.5)	(16.6)	(17.7)
265	Net SLB	(0.3)	(0.1)																	
266	CoBank Patronage Capital	(0.4)	(0.1)	-	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)
267	Adjustment	0.2	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
268	Total	1.6	(0.6)	-	(23.6)	(0.5)	(1.5)	6.6	(0.9)	(0.9)	(1.2)	(2.4)	(0.5)	(4.3)	2.5	(3.5)	1.1	(2.2)	1.0	(2.2)
269																				
270	Cash Balance																			
271	Beginning	96.5	138.4	134.9	160.0	173.6	139.7	119.3	181.5	246.8	314.6	391.3	459.4	525.5	558.8	620.8	658.4	719.1	773.3	841.0
272	Ending	138.4	134.9	160.0	173.6	139.7	119.3	181.5	246.8	314.6	391.3	459.4	525.5	558.8	620.8	658.4	719.1	773.3	841.0	911.5
273																				
274	**VI. Credit Measures**																			
275																				
276	Contract TIER																			
277	Earnings				10.6	15.8	13.3	100.0	91.1	80.1	86.8	75.1	75.0	27.8	67.9	39.9	64.4	56.5	77.3	74.8
278	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
279	Plus: Imputed Rate Increase in 2010				-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
280	Less: Offset to Imputed Rate Increase in 2010				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Less: Interest on Sequestered Funds				(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
282	Total				40.7	60.5	59.8	144.8	135.2	123.4	129.2	116.6	115.5	67.2	106.3	77.1	100.4	91.3	110.8	106.8
283	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
284	Total				49.6	73.8	73.7	159.3	150.3	139.1	145.5	133.6	133.2	85.8	125.7	97.4	121.8	113.7	134.3	131.5
285	Divided by																			
286	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
287	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
288	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
289																				
290	*Contract TIER*				1.24	1.24	1.24	2.69	2.54	2.36	2.48	2.29	2.29	1.48	2.18	1.69	2.12	1.99	2.35	2.32
291																				
292	Conventional TIER																			
293	Earnings				10.6	15.8	13.3	100.0	91.1	80.1	86.8	75.1	75.0	27.8	67.9	39.9	64.4	56.5	77.3	74.8
294	Plus: Interest Expense, Financing Fees, and Restucturing				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
295	Plus Income Tax				-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
296	Total				41.7	62.1	58.9	144.8	135.2	124.0	129.8	117.2	116.2	68.0	107.1	77.9	101.3	92.2	111.8	107.8
297	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
298	Total				50.6	75.4	72.8	159.3	150.3	139.7	146.2	134.3	134.0	86.6	126.5	98.3	122.6	114.6	135.3	132.5
299	Divided by																			
300	Interest Expense, Financing Fees, and Restructuring				31.1	46.2	45.5	44.8	44.1	43.3	42.3	41.4	40.5	39.4	38.4	37.2	36.1	34.8	33.6	32.0
301	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
302	Total				40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
303																				
304	*Conventional TIER*				1.27	1.27	1.22	2.69	2.54	2.37	2.49	2.30	2.30	1.49	2.19	1.71	2.14	2.01	2.37	2.34
305																				

	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			4/30/2008	
306	DSCR - Cash Basis, Pre Capex, incl Sale-Leaseback																			
307	Cash Available for Debt Service																			
308	Receipts less Disbursements				84.6	88.0	77.5	141.9	164.3	161.8	172.8	164.2	162.6	132.1	166.5	143.5	164.7	160.5	173.6	178.2
309	*Economic Reserve*				5.5	12.5	19.1	34.9	13.3	-	-	-	-	-	-	-	-	-	-	-
310	Taxes				(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.3)	(0.4)	(0.4)	(0.4)	(0.4)	(0.5)	(0.5)	(0.5)	(0.5)	(0.6)
311	Net				90.2	100.5	96.6	176.8	177.6	161.8	172.5	163.9	162.2	131.7	166.1	143.1	164.2	160.0	173.0	177.6
312	Plus Sale-Leaseback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
313	Total				99.1	113.8	110.5	191.3	192.6	177.5	188.8	180.9	180.0	150.3	185.5	163.4	185.6	182.3	196.5	202.3
314	Divided by																			
315	Interest Expenditures				27.2	39.9	38.8	37.7	36.5	35.3	34.0	32.5	31.1	29.5	27.8	26.1	24.2	22.2	20.2	18.1
316	Scheduled Principal				11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
317	Plus Sale-Leasback Interest				8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
318	Total Debt Service				48.0	71.7	72.3	72.9	73.5	74.1	74.7	75.4	76.2	77.0	77.8	78.7	79.7	80.8	81.9	83.1
319																				
320	*DSCR*				2.06	1.59	1.53	2.62	2.62	2.40	2.53	2.40	2.36	1.95	2.38	2.08	2.33	2.26	2.40	2.43
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.8	156.6	129.5	150.4	214.1	280.7	353.0	425.4	492.5	542.1	589.8	639.6	688.7	746.2	807.1	876.3
324	Line of Credit				*66.9*	*100.0*	*100.0*	*100.0*	*100.0*	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
325	Total	117.5	136.7	147.5	233.8	256.6	229.5	250.4	314.1	380.7	453.0	525.4	592.5	642.1	689.8	739.6	788.7	846.2	907.1	976.3
326	Divided by																			
327	Total Operating Expense																			
328	PPA	87.9	34.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
329	Fuel Costs	-	-	-	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
330	SEPA & Other Purchases	6.9	3.8	-	11.5	22.3	18.9	7.2	8.9	7.3	7.5	7.5	8.3	8.6	8.4	8.7	8.6	8.7	8.8	8.9
331	Non-Fuel Variable Production O	0.7	0.3	-	18.3	29.0	31.4	32.1	35.3	36.0	37.6	41.5	42.5	42.2	44.9	44.5	46.5	48.8	49.4	51.6
332	Fixed Production O&M	-	-	-	64.2	93.2	88.3	100.7	100.7	101.8	101.3	111.0	106.8	127.8	110.9	127.6	121.6	131.7	126.4	135.1
333	Transmission O&M	7.4	2.5	-	5.1	7.8	8.1	8.3	8.6	8.8	9.1	9.4	9.6	9.9	10.2	10.5	10.9	11.2	11.5	11.9
334	APM, L/C, Cogen, CW & TVA T	3.8	3.6	-	3.5	5.3	5.4	4.7	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.6	5.8	6.0	6.2	6.3
335	A&G	13.8	4.9	-	17.9	25.0	24.2	25.0	25.4	26.1	27.3	27.7	28.6	29.8	30.3	31.2	32.5	33.1	34.1	35.5
336	Property Taxes & Insurance	2.4	0.8	-	4.5	6.9	7.1	7.8	8.5	8.8	9.1	9.3	9.6	9.9	10.2	10.5	10.8	11.1	11.5	11.8
337	Interest Expense (Incl. Financin	60.0	19.3	-	31.0	46.1	45.4	44.7	44.0	43.0	42.0	41.1	40.2	39.2	38.1	37.0	35.8	34.5	33.1	31.5
338	Total	182.8	69.2	-	293.6	439.0	450.9	444.4	458.4	466.8	481.9	495.0	493.9	512.9	510.8	525.8	528.7	542.7	544.7	562.3
339																				
340	*Days Cash on Hand (including Line o*	234.5	721.0		290.6	213.4	185.8	205.6	250.1	297.7	343.0	387.4	437.8	457.0	492.9	513.4	544.5	569.1	607.9	633.7
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		207.4	130.2	104.8	123.5	170.5	219.5	267.3	313.6	363.9	385.8	421.4	444.0	475.4	501.8	540.9	568.8
342																				

		2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Calendar Year																			
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	*0.000*	*0.000*	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
																Transaction Closing Date:			*4/30/2008*	
343	**VII. Debt Service Detail, as of Transaction Date (M$)**																			
344																				
345	Fixed/ Insured Serial Bonds (Tranche 1)																			
346	Beginning Principal		-	-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
347	Principal		-	(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest		-	-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
349	Debt Service		-	(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
350	*Blended Interest Cost*		0.00%	0.00%	3.78%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%	5.64%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal		-	-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
354	Principal		-	(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
355	Interest		-	-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
356	Debt Service		-	(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
357	Blended Interest Cost		0.00%	0.00%	3.68%	5.49%	5.49%	5.49%	5.49%	5.49%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.50%	5.52%
358																				
359	Variable Rate Bonds																			
360	Beginning Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
361	Principal		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
362	Interest		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
363	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
364	Blended Interest Cost		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
365																				
366	Ongoing RUS Note (Stated)																			
367	Beginning Principal		-	794.7	352.0	340.1	321.7	302.4	281.9	260.2	237.3	213.0	187.4	160.3	131.6	101.3	69.3	35.4	-	-
368	Principal		-	442.7	11.9	18.3	19.4	20.5	21.7	22.9	24.2	25.6	27.1	28.7	30.3	32.1	33.9	35.4	-	-
369	Interest		-	-	13.5	19.6	18.5	17.4	16.2	15.0	13.6	12.2	10.8	9.2	7.6	5.8	4.0	2.0	-	-
370	Debt Service		-	442.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
371	Blended Interest Cost			0.00%	3.85%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%		
372																				
373	ARVP																			
374	Beginning Principal		-	101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
375	Principal/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
376	Interest/ Reserve		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
377	Debt Service		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
378	*Accretion Rate*		0.00%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
379																				
380	PCB																			
381	Beginning Principal		-	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
382	Principal		-	-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
383	Interest		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
384	Debt Service		-	-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
385	Blended Interest Cost			0.00%	2.41%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal		-	1,038.3	*859.1*	851.2	*839.0*	*826.0*	812.3	797.9	782.6	766.5	749.5	731.5	712.4	692.3	671.1	648.6	624.9	599.9
389	Principal		-	179.2	11.9	18.5	19.6	20.7	21.9	23.1	24.5	25.9	27.3	28.9	30.6	32.3	34.2	36.2	38.2	40.3
390	Interest		-	-	26.8	39.4	38.3	37.2	36.0	34.8	33.5	32.0	30.6	29.0	27.3	25.6	23.7	21.7	19.7	17.6
391	Line of Credit Fee		-	-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
392	Debt Service		-	179.2	39.1	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4	58.4

Smelter Rate Structure

	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Days in Year		365	365	365	366	365	365	365	366	365	365	365	366	365	365	365
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
1 <u>Smelter Sales</u>																
2 Century	2.79	4.16	4.16	-	-	-	-	-	-	-	-	-	-	-	-	-
3 Alcan	2.11	3.14	3.14	-	-	-	-	-	-	-	-	-	-	-	-	-
4 Total Energy (TWh)	4.898	7.297	7.297	-	-	-	-	-	-	-	-	-	-	-	-	-
5 Total Demand (GW)	6.847	10.200	10.200	-	-	-	-	-	-	-	-	-	-	-	-	-
6 Smelter Load Factor (%)	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
7																
8 <u>Smelter Rate ($/ MWh)</u>																
9 <u>Large Industrial Rate</u>																
10 Sales (TWH)	0.69	1.06	1.10	1.13	1.17	1.20	1.23	1.27	1.30	1.34	1.37	1.41	1.44	1.48	1.51	1.54
11 Load Factor (%)	78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
12 Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
13 Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
17 Less: Regulatory Account Charge	-	-	-	-	-	0.21	0.21	0.20	-	-	-	-	-	-	-	(0.00)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	30.51	30.53	30.55	30.56	30.58	30.61	30.62	30.63	30.65	30.69	30.68	30.69	30.71
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	27.11	27.09	27.15	27.16	27.18	27.16	27.21	27.23	27.24	27.22	27.27	27.28	27.29
21 Plus Margin	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
22 Smelter Base Rate	27.32	27.33	27.34	27.36	27.34	27.40	27.41	27.43	27.41	27.46	27.48	27.49	27.47	27.52	27.53	27.54
23 Plus TIER Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24 Less TIER Related Rebate	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-
28 Plus Surcharge 1	0.70	0.70	0.70	-	-	-	-	-	-	-	-	-	-	-	-	-
29 Plus Surcharge 2	1.20	0.72	1.20	-	-	-	-	-	-	-	-	-	-	-	-	-
30 Effective Smelter Rate (Incl. PPA, Surcharge, & Rebate)	34.82	34.94	37.69	-	-	-	-	-	-	-	-	-	-	-	-	-
31																
32 <u>TIER Adjustment Cap ($/ MWh)</u>																
33 Bandwidth Floor	27.32	27.33	27.34	-	-	-	-	-	-	-	-	-	-	-	-	-
34 Bandwidth Range	1.95	1.95	1.95	1.95	2.95	2.95	2.95	3.55	3.55	3.55	4.15	4.15	4.15	4.75	4.75	4.75
35 Bandwidth Ceiling	29.27	29.28	29.29	-	-	-	-	-	-	-	-	-	-	-	-	-
36 Smelter Rate Subject to TIER Adjustment/ Rebate	27.08	26.78	26.43	-	-	-	-	-	-	-	-	-	-	-	-	-


Smelter Price and Bandwidth
39.00
37.00
35.00
33.00
31.00
29.00
27.00
25.00
2008 H2
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
Smelter Rate Subject to TIER Adjustment/ Rebate
FAC + PPA + Environmental Surcharge
Surcharge 1
Surcharge 2
Bandwidth Floor
Bandwidth Ceiling

Smelter Rate Structure

December 2007

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	121.0	125.2	129.6	161.1	181.4	189.4	199.3	205.7	211.4	219.7	225.5	233.7	240.9	248.5	257.8
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Revenues	75.8	115.1	102.9	456.6	443.0	421.4	439.5	434.3	428.9	405.5	445.6	423.6	449.3	452.3	470.4	481.9
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	586.3	604.1	602.9	628.9	633.6	634.6	617.0	665.3	649.1	683.0	693.2	718.8	739.6
Total Expenses	315.2	473.3	486.4	486.2	513.0	522.7	542.1	558.5	559.6	589.2	597.4	609.3	618.6	636.6	641.6	664.8
Net Margin Before TIER Adjustment	12.3	21.7	23.3	100.0	91.1	80.1	86.8	75.1	75.0	27.8	67.9	39.9	64.4	56.5	77.3	74.8
Interest + Margin	52.4	81.2	82.7	159.3	150.3	139.1	145.5	133.6	133.2	85.8	125.7	97.4	121.8	113.7	134.3	131.5
Interest Charges	40.0	59.6	59.4	59.3	59.2	58.9	58.6	58.4	58.3	58.0	57.8	57.6	57.4	57.1	57.1	56.7
Pre-TIER Adjustment TIER	1.31	1.36	1.39	2.69	2.54	2.36	2.48	2.29	2.29	1.48	2.18	1.69	2.12	1.99	2.35	2.32
Increment needed for 1.24x TIER	(2.7)	(7.4)	(9.0)	(85.8)	(76.9)	(66.0)	(72.8)	(61.1)	(61.0)	(13.9)	(54.1)	(26.0)	(50.6)	(42.8)	(63.6)	(61.2)
Contract TIER Adjustments																
Plus: Imputed Rate Increase in 2010	-	-	2.5	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Offset to Imputed Rate Increase in 2010	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Less: Interest on Sequestered Funds	(1.0)	(1.5)	(1.6)	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Adjustments	(1.0)	(1.5)	0.9	-	-	-	-	-	-	-	-	-	-	-	-	-
Increment needed for 1.24x TIER with Adj.	(1.7)	(5.8)	(9.9)	(85.8)	(76.9)	(66.0)	(72.8)	(61.1)	(61.0)	(13.9)	(54.1)	(26.0)	(50.6)	(42.8)	(63.6)	(61.2)
Rebate Amount ($M)	(1.74)	(5.84)	(9.94)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Rebate to Members/Smelters ($/MWh)																
Rurals	(0.25)	(0.56)	(0.95)	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	(0.22)	(0.49)	(0.83)	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Member Rates Cash Method

		2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Member Sales (TWh)**																
2	Rural	1.6	2.4	2.5	2.5	2.6	2.7	2.7	2.8	2.8	2.9	2.9	3.0	3.1	3.1	3.2	3.2
3	Large Industrial	0.7	1.1	1.1	1.1	1.2	1.2	1.2	1.3	1.3	1.3	1.4	1.4	1.4	1.5	1.5	1.5
4	Total	2.3	3.5	3.6	3.7	3.8	3.9	3.9	4.0	4.1	4.2	4.3	4.4	4.5	4.6	4.7	4.8
5																	
6	**Rates (Cash Method)**																
7	***Rural***																
8	Load Factor (%)	60.2%	60.0%	60.1%	60.2%	60.2%	60.4%	60.5%	60.6%	60.5%	60.7%	60.8%	60.9%	60.8%	61.0%	61.1%	61.2%
9	Demand ($/ KW-mo.)	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37	7.37
10	Energy ($/ MWH)	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40	20.40
11	Base	37.18	37.22	37.19	37.17	37.14	37.12	37.09	37.07	37.04	37.02	37.00	36.98	36.95	36.94	36.92	36.90
12	MRDA	(1.11)	(1.10)	(1.08)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.94)	(0.92)	(0.90)	(0.88)	(0.86)	(0.84)	(0.82)	(0.81)
13	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
14	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
16	Env. Surcharge	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
17	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
18	TIER Related Rebate	-	(0.17)	(0.55)	(0.93)	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
20	Net	-	(0.01)	(0.02)	(0.04)	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
21	Effective Rate	36.07	36.11	36.09	36.07	44.57	48.84	49.83	51.17	51.63	51.89	52.74	52.94	53.68	54.15	54.71	55.59
22																	
23	***Large Industrial***																
24	Load Factor (%)	78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
25	Demand ($/ KW-mo.)	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15	10.15
26	Energy ($/ MWH)	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72	13.72
27	Base	31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
28	MRDA	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
29	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
30	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
32	Env. Surcharge	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
33	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
34	TIER Related Rebate	-	(0.14)	(0.47)	(0.80)	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
36	Net	-	0.02	0.06	0.09	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
37	Effective Rate	30.58	30.48	30.54	30.59	39.00	43.27	44.28	45.64	46.15	46.40	47.27	47.49	48.27	48.73	49.31	50.20
38																	
39	***Non-Smelter Member Blend***																
40	Base	35.50	35.45	35.42	35.39	35.36	35.33	35.31	35.28	35.26	35.24	35.21	35.20	35.18	35.16	35.14	35.13
41	MRDA	(1.06)	(1.05)	(1.03)	(1.00)	(0.98)	(0.96)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.84)	(0.82)	(0.80)	(0.78)	(0.77)
42	Regulatory Account Charge	-	-	-	-	-	(0.21)	(0.21)	(0.20)	-	-	-	-	-	-	-	0.00
43	GRA	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
45	Env. Surcharge	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
46	Surcharge Rebate	(4.00)	(2.95)	(3.87)	-	-	-	-	-	-	-	-	-	-	-	-	-
47	TIER Related Rebate	-	(0.16)	(0.53)	(0.89)	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.58)	(5.33)	(9.50)	(3.54)	-	-	-	-	-	-	-	-	-	-	-
49	Net	-	0.00	0.00	0.00	8.46	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
50	Effective Rate	34.44	34.40	34.39	34.39	42.84	47.11	48.09	49.43	49.90	50.15	51.00	51.20	51.95	52.41	52.97	53.85
51																	
52	***Revenues Delta($M)***																
53	Rural	0.41	0.97	0.99	(2.37)	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	0.15	0.37	0.39	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	0.56	1.34	1.38	(3.28)	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Accrued ($/ MWh)	(0.24)	(0.54)	(0.91)	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		(0.16)	(0.54)	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	1.18	2.77	2.72	-	-	-	-	-	-	-	-	-	-	-	-	-

Regulatory Accounts

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Purchased Power Cost not Included in Member Rates ($M)	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
1	**EXPENSE DEFERRAL METHOD**																
2																	
3	**Income Statement (Change in Regulatory Account)**																
4	1. Deferral																
5	Power Purchase Expense																
6	Debit	1.26	-	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Credit	-	(0.17)	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Total	1.26	(0.17)	1.33	-	-	-	-	-	-	-	-	-	-	-	-	-
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
12	Debit Power Purchase Expense						(0.81)	(0.81)	(0.81)	-	-	-	-	-	-	-	0.00
13																	
14	Net Income	(1.26)	0.17	(1.33)	-	-	-	-	-	-	-	-	-	-	-	-	-
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
19	Regulatory Asset	-	-	-	-	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	Total	-	-	-	-	-	(0.81)	(1.61)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)	(2.42)
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)
24	Regulatory Liability	1.3	1.1	2.4	2.4	2.4	1.6	0.8	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	-	-	(0.8)	(1.6)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)	(2.4)

FAC PPA Env Sur

December 2007

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	**Production (TWh)**	8.1	11.8	12.1	11.3	11.5	11.5	11.8	11.7	11.7	11.3	11.8	11.4	11.6	11.6	11.7	11.8
2	**Sales (TWh)**	8.3	12.3	12.5	11.6	11.8	11.7	12.0	12.0	11.9	11.5	12.0	11.6	11.8	11.9	11.9	12.0
3																	
4																	
5	**A. FAC**																
6	Fuel Costs ($M)	137.6	203.5	222.0	214.0	222.5	230.2	243.4	242.4	243.2	240.2	252.3	250.2	256.2	257.6	263.7	269.5
7																	
8	Total Costs for Passthrough ($/ MWh Sold	16.62	16.56	17.77	18.48	18.86	19.69	20.25	20.26	20.44	20.91	20.99	21.48	21.66	21.71	22.13	22.46
9	Fuel Cost Base ($/MWh)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)	(10.72)
10	FAC ($/MWh)	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
11	**B. PPA**																
12	Purchased Power Costs ($M)	10.01	22.11	17.26	6.88	8.58	7.81	7.94	7.95	7.94	8.24	8.12	8.34	8.29	8.42	8.52	8.57
13																	
14	Total Costs for Passthrough ($/ MWh Sold	1.21	1.80	1.38	-	-	-	-	-	-	-	-	-	-	-	-	-
15	Purchased Power Cost Base ($/MWh)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)	(1.75)
16	Purchase Power Passthrough ($/MWh)	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
17																	
18	**C. Environmental Surcharge**																
19	Eligible Cost ($M)	4.06	10.44	33.45	30.34	45.54	46.45	52.79	68.39	69.07	64.17	76.56	70.76	78.55	83.81	85.92	93.08
20																	
21	Total Costs for Passthrough ($/ MWh Sold	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
22	Env. Surcharge Cost Base ($/MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Environmental Surcharge Passthrough ($/	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
24																	
25																	
26	**1 - FAC + Environmental Surcharge to Members**																
27	Rurals																
28	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
29	Environmental Surcharge	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
30	**Total**	6.39	6.69	9.73	10.39	12.00	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
31	Large Industrials																
32	FAC	5.90	5.84	7.05	7.77	8.14	8.97	9.53	9.54	9.73	10.19	10.27	10.77	10.94	10.99	11.41	11.74
33	Environmental Surcharge	0.49	0.85	2.68	2.62	3.86	3.97	4.39	5.72	5.81	5.59	6.37	6.08	6.64	7.06	7.21	7.75
34	**Total**	6.39	6.69	9.73	10.39	12.00	12.94	13.93	15.26	15.53	15.78	16.64	16.84	17.58	18.05	18.62	19.50
35	**2 - FAC + PPA + Environmental Surcharge to Smelters**																
36	FAC	5.90	5.84	7.05	-	-	-	-	-	-	-	-	-	-	-	-	-
37	PPA	(0.54)	0.05	(0.37)	-	-	-	-	-	-	-	-	-	-	-	-	-
38	Environmental Surcharge	0.49	0.85	2.68	-	-	-	-	-	-	-	-	-	-	-	-	-
39	**Total**	5.85	6.74	9.36	-	-	-	-	-	-	-	-	-	-	-	-	-

UW Transaction

($M)

		2007	2008H1 0	Transaction	2008 H2 0
	Unwind Allocation	-	-	-	0.669
	Pre-Transaction Allocation	1.000	0.331	-	-
	Transaction Index	-	-	1.000	-
	A. Transaction Components				
1	1. Cash Payment/ Credit Escrow Draws	-	-	301.5	-
2	2. WKE Residual Value Obligation				
3	WKE Gen. Capex - Cum.				
4	Non-Incremental (RV Obligation Balance)				
5	Beginning Balance	45.2	50.2	61.0	-
6	WKE Share of Non-Incremental Capex	6.8	11.7	-	-
7	Amortization of WKE Share	1.8	0.9	-	-
8	Net	50.2	61.0	61.0	-
9	Incremental				
10	Beginning Balance	95.6	90.9	89.4	-
11	WKE Share of Non-Incremental Capex	-	-	-	-
12	Amortization of WKE Share	4.6	1.6	-	-
13	Net	90.9	89.4	89.4	-
14	Total	141.1	150.4	150.4	
15	3. LG&E Rental Income Advance				
16	Cash Flow	48.0	15.8	-	-
17	Income Statement	52.3	17.3	-	-
18	Balance	(13.0)	(11.4)	(11.4)	-
19	4. Fuel & Other Inventories	-	-	55.0	-
20	5. Cancellation of Settlement Prom. Note	-	-	16.0	-
21	6. Coleman Scrubber Completion	-	-	97.5	-
22	7. LG&E Emissions Allowance	-	-	10.9	-
23	8. Expense Unamortized Mktg Payment/ Settlement Note			(15.7)	
24	9. Assurances Agreement	-	-	4.3	-
25					
26	Total Residual Value Obligation	154.1	161.8	161.8	-
27	Cancellation of RV Obligation				
28	Reclassification as Equity	-	-	161.8	-
29					
30	Net WKE Obligation	154.1	161.8	-	-
31					

December 2007

UW Transaction

			2007	2008H1	Transaction	2008 H2
	($M)					
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
32						
33	**B. Transaction Cash Flows**					
34	Cash Balances Pre-Transaction				134.9	
35	Transaction Proceeds				301.5	
36	Smelter Payment (Assurances Agreement)				(4.3)	
37	Consent Fee to Lease-Equity Parties				-	
38	Lump-Sum Member Rebate				-	
39	Net DSL Termination				-	
40	Century/Century Reactive Power Transaction Refund				(0.3)	
41	Income Tax				(1.1)	
42	Net Transaction Cash				295.9	
43	Debt Restructuring:					
44	Debt Reduction (Net)				(186.2)	
45	Underwriting Costs	1.75%			(4.6)	
46	Bond Insurance	0.80%			(5.0)	
47	ARVP Defeasance Premium				-	
48	Total				(195.8)	
49	Restricted Cash Balances:					
50	Transition Reserve				(35.0)	
51	Economic Reserve				(75.0)	
52	Unrestricted Cash Balances Post-Transaction				125.0	
53						
54	**C. Debt Restructuring:**					
55	Beginning Balance - GAAP				1,051.1	
56	Cancellation of Settlement Prom. Note				(16.0)	
57	Capitalize Accrued Interest on RUS New Note				7.2	
58	Step-Up RUS New Note to Stated Basis:					
59	GAAP RUS New Note					
60	Ending Balance				791.4	
61	Accrued Interest				7.2	
62	Total				798.6	
63	Stated RUS New Note					
64	Ending Balance				794.7	
65	Accrued Interest				7.0	
66	Total				801.7	
67	Step-Up				3.1	
68	Beginning Balance - Stated				1,045.3	
69	Cash Flow:					
70	Prepay RUS New Note				(449.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				263.5	
73	Net				(186.2)	
74	Ending Balance - Stated				859.2	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.3)	
76	Ending Balance - GAAP				857.8	
77						

UW Transaction

	($M)		2007	2008H1	Transaction	2008 H2
				0		0
	Unwind Allocation		-	-	-	0.669
	Pre-Transaction Allocation		1.000	0.331	-	-
	Transaction Index		-	-	1.000	-
78	**D. Reflection on Income Statement**					
79	1. Cash		-	-	301.500	-
80	2. Residual Value Payment		-	-	150.394	-
81	3. LG&E Rental Income Advance		-	-	11.445	-
82	4. Fuel Inventory & Other		-	-	55.000	-
83	5. Settlement Promissory Note		-	-	16.025	-
84	6. Coleman Scrubber		-	-	97.495	-
85	7. SO2 Allowances				10.892	
86	8. Expense Unamortized Mktg Payment/ Settlement Note		-	-	(15.740)	-
87	9. Assurances Agreement Payment				(4.263)	
88	Total		-	-	622.748	-
89						
90	**E. Non-Patronage Allocations and Taxable Income**					
91						
92	**Cash Flows**	15%	-	-	45.23	-
93						
94	**Income Statement**					
95	Cash	15%	-	-	45.23	-
96	RVP	15%	-	-	24.28	-
97	Fuel Inventory & Other (plus emissions allowances)	15%	-	-	9.88	-
98	Settlement Promissory Note	15%	-	-	2.40	-
99	Coleman Scrubber	15%	-	-	14.62	-
100	Expense Unamortized Mktg Payment/ Settlement Note	15%	-	-	(5.93)	-
101		15%				
102	Total		-	-	90.49	-
103						
104	**Taxable Income**					
105	Gain on Transaction (above)		-	-	90.49	-
106	Less RVP		-	-	(24.28)	-
107	Less M1 - Coleman Scrubber		-	-	(14.62)	-
108	Plus Previously Expensed Mktg. Pmt.		-	-	4.20	-
109	Total		-	-	55.78	-
110						
111	**Assumptions**					
112	(a) Non-Patronage Allocation:					
113	Transaction Settlement Attribution					
114	Patronage Eligible	89%				
115	Patronage	11%				
116	Non-Patronage	0%				
117	Patronage Eligible Allocation (based on retrospective sales)					
118	Patronage	85%				
119	Non-Patronage	15%				
120	Non-Patronage Allocation:	13%				
121						
122	(b) Base case posits no tax basis to Big Rivers. Will be treated as a non-shareholder					
123						
124	(c) Base case posits no tax basis to Big Rivers. Improvements made by LG&E, therefore no additional income.					
125						
126	(d) 100% non-patron for book and tax. As a result, the reversal will be treated in the same manner for consistency purposes.					

Production-Fixed

Production - Fixed

	($M)	2007	2008 H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	A&G																		
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total	13.80	4.86	17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
7																			
8	APM, L/C, Cogen, CW & TVA Trans	3.83	3.63	3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9																			
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11																			
12	Property Tax																		
13	Baseline	1.08	0.37	1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17																			
18	Transmission O&M																		
19	Baseline Labor	7.38	1.89	3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I																		
22	O&M	-	0.08	0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	-	0.01	0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	-	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	-	0.10	0.20	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)		0.10	0.21	0.32	0.33	0.34	0.35	0.36	0.37	0.38	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	7.38	2.52	5.10	7.84	8.08	8.32	8.57	8.83	9.09	9.36	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28																			
29	Fixed O&M																		
30																			
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32																			
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34																			
35	Plant Maintenance																		
36	Coleman			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44																			
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
47																			
48	Environmental Monitoring and Other			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49																			
50	08/2007 Adjustment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51																			
52	Total Fixed O&M (to Cash Flows)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	Transmission--Basic		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
2																					
3	Transmission Upgrades																				
4	Phase I		-	4.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Phase II		-	-	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Total Real		-	4.00	-	3.70	5.80	1.60	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Total Nominal	3.00%	-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
8																					
9	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
10																					
11	Shared HQ Building																				
12	Phase I		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Phase II		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Total		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15																					
16	Intellectual Property																				
17	Total			-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
18																					
19	WKE Share of Generation Capex																				
20	(%)		51%	51%	84%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	(M$)		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22																					
23	Generation																				
24	Baseline		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
25	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Total Real		-	-	-	22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
27	Total Nominal	3.00%	13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
28																					
29	Plant Maintenance																				
30	Coleman		-	-	-	3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
31	Green		-	-	-	-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
32	HMP&L		-	-	-	1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
33	Reid		-	-	-	-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
34	Wilson		-	-	-	4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
35	Adjustment for Station 2		-	-	-	(0.44)	(0.41)	(0.26)	(1.89)	(1.26)	-	(1.12)	-	-	-	-	(0.28)	(0.28)	-	-	-
36	Total Real		-	-	-	8.67	19.47	18.54	17.62	11.37	1.32	2.37	-	-	-	1.28	2.77	0.60	-	-	-
37	Total Nominal	3.00%	-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
38																					
39	Environmental																				
40	NOx Removal Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
41	Mecury Monitoring		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Clmn FGD Equipment Capital		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
43	FGD ongoing upkeep capital (0.10%)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
44	Additional FGD thickener & filter drum		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
45	R-CT reliability study & upgrades		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
46	Wilson super heater tubes replacment		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Adjustment for Station 2		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	*Total Real*		-	-	-	3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Total Nominal	3.00%	-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																					
51																					
52																					
53	BigRivers Capex																				
54	*Gross Generation*		13.12	13.41	13.95	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
55	*Less* WKE Generation Share		6.69	6.84	11.73	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56	BigRivers Generation		6.43	6.57	2.22	14.61	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60	40.79
57	Transmission		5.91	9.62	5.19	6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
58	Transmission Upgrades		-	4.12	-	3.70	5.97	1.70	-	-	-	-	-	-	-	-	-	-	-	-	-
59	A&G		0.86	1.25	0.43	0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
60	Shared HQ Building		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Intellectual Property		-	-	-	4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
62	Plant Maintenance		-	-	-	5.65	21.27	20.86	20.42	13.58	1.62	3.00	-	-	-	1.83	4.07	0.91	-	-	-
63	Environmental		-	-	-	1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
64	08/2007 Adjustment				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
65	Cash Adder		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Total		13.19	21.56	7.84	37.45	76.01	58.58	56.26	53.85	35.54	37.47	37.30	37.79	40.02	45.68	47.10	45.13	47.37	46.91	48.76

Capex & Depreciation

December 2007

	($M)	2005	2006	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
67																					
68																					
69	**<u>Depreciation</u>**																				
70																					
71	<u>Additional Book Depreciation</u>																				
72	Prior year non-incremental + in service		12.83	13.12	4.43	9.34	133.67	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60
73	Current year non-incremental + in service		13.12	13.41	13.95	119.72	53.79	44.60	49.22	43.64	31.98	34.26	32.20	33.17	34.16	37.02	40.31	38.24	38.45	39.60	40.79
74	Average of Production		12.97	13.26	9.19																
75	Prior year Transmission and A&G					10.03	16.06	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
76	Current year Transmission and A&G					10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
77	Average of Transmission and A&G		6.38	10.88	5.29																
78	Total		19.35	24.14	14.48																
79	Rate to Apply to 2007 Capital in 08		1.53%	1.53%	1.54%	1.54%															
80	Capital Depreciation Rate (excl. Environmental)					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
81	Additional Depreciation		0.30	0.37	0.22	1.15	1.79	1.03	1.47	1.40	1.12	0.92	0.93	0.93	0.99	1.06	1.15	1.17	1.15	1.18	1.21
82																					
83	<u>HMP&L Station Two</u>																				
84	Prior year non-incremental		12.83	13.12	4.43	8.98	28.56	32.52	23.74	28.80	30.06	30.35	31.26	32.20	33.17	34.16	35.19	36.24	37.33	38.45	39.60
85	Depreciation as a Percentage of Gross PPE		0.05%	0.05%	0.05%	0.11%	0.11%	0.11%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.11%	0.11%	0.11%	0.11%	0.11%	0.11%
86	Additional Depreciation		0.01	0.01	0.00	0.01	0.03	0.03	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
87																					
88	<u>Environmental</u>																				
89	Prior year environmental						1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97	1.97
90	Current year environmental					1.97	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	Environmental Depreciation Rate					1.54%	1.63%	1.62%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%	2.63%
92	Additional Depreciation					0.03	0.03	0.03	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
93																					
94	<u>Other</u>																				
95	Prior year		6.00	6.77	4.96	10.03	16.39	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73
96	Current year		6.77	10.87	5.62	10.77	16.86	12.25	5.83	7.36	1.96	1.90	2.08	3.22	4.49	5.09	5.24	5.40	5.56	5.73	5.90
97	Average		6.38	8.82	5.29																
98	Rate to Apply to 2007 Capital in 08		0.00	0.00	0.00	0.00															
99	Capital Depreciation Rate (excl. Environmental)					0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%
100	Additional Depreciation		0.02	0.03	0.02	0.05	0.10	0.09	0.05	0.04	0.03	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03
101																					
102	<u>Book Depreciation & Amortization</u>																				
103	Generation																				
104	Big Rivers' Plants		25.36	25.39	8.582	19.62	31.13	32.20	49.75	51.19	52.36	53.34	54.32	55.30	56.34	57.45	58.66	59.88	61.09	62.31	63.58
105																					
106	Intellectual Property					0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
107	HMP&L Station Two		1.58	1.64	0.543	0.64	0.98	1.02	1.04	1.07	1.10	1.13	1.16	1.19	1.23	1.27	1.30	1.34	1.38	1.43	1.47
108	Total Generation Depr & Amort		26.94	27.03	9.125	20.33	32.28	33.40	51.12	52.67	53.92	54.95	56.05	57.10	58.21	59.45	60.73	62.04	63.37	64.68	66.04
109	Other		5.05	5.25	1.750	3.50	5.28	5.37	5.42	5.46	5.48	5.50	5.51	5.52	5.54	5.57	5.60	5.63	5.67	5.70	5.73
110	Blended Depreciation Adj.		-	-	-	-	-	-	(11.53)	(11.66)	(12.93)	(13.90)	(13.46)	(13.08)	-	-	-	-	-	-	-
111	Total		31.99	32.27	10.88	23.83	37.56	38.77	45.01	46.47	46.47	46.55	48.09	49.54	63.75	65.02	66.34	67.67	69.04	70.38	71.78
112																					
113	Years Depreciation						52	52	46	46	47	48	47	47	37	37	37	37	37	37	37

Unwind Debt

December 2007

	($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
			0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
1	Fixed/ Insured (Tranche 1)																			
2	Beginning Balance			-	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5	181.5
3	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
4	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Interest			-	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
6	Principal			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service			(181.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
8																				
9	Fixed/ Insured (Tranche 2)																			
10	Beginning Balance			-	82.0	82.0	81.8	81.7	81.5	81.3	81.1	80.9	80.7	80.4	80.2	79.9	79.6	79.3	78.6	40.3
11	Coupon			0.00%	5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
12	Principal (%)			0.00%	0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
13	Interest			-	3.0	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.4	4.4	4.3	2.2
14	Principal			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
15	Debt Service			(82.0)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
16																				
17	RUS -- GAAP																			
18	Beginning Balance			791.4	350.7	338.7	320.6	301.3	281.0	259.4	236.6	212.5	187.0	160.0	131.4	101.2	69.2	35.3	-	-
19	Coupon			0.00%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
20	Principal (%)			0.00%	3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
21	Interest			-	13.5	19.7	18.6	17.5	16.3	15.1	13.8	12.4	10.9	9.3	7.6	5.9	4.0	2.1	-	-
22	Principal + Accrued Interest			440.7	12.0	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.9	35.3	-	-
23	Debt Service			440.7	25.5	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.9	37.4	-	-
24																				
25	Variable																			
26	Beginning Balance			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Coupon			0.00%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
28	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
29	Interest+Remarketing			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
31	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
32																				
33	PCB																			
34	Beginning Balance			142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1	142.1
35	Coupon			0.00%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
36	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
37	Interest			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
38	Principal			-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service			-	3.4	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1
40																				
41	ARVP																			
42	Beginning Balance			101.5	101.5	105.6	111.8	118.4	125.4	132.8	140.7	149.0	157.8	167.2	177.0	187.5	198.6	210.3	222.8	236.0
43	Accretion Rate	5.9%		5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%	5.91%
44	Interest Rate			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
45	Principal (%)			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.000%	0.00%
46	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
47	Interest			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Principal			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Debt Service			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50																				
51	Total																			
52	Beginning Balance			1,035.0	857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9
53	Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
54	Principal			177.2	12.0	18.3	19.4	20.5	21.7	23.0	24.3	25.7	27.2	28.8	30.5	32.3	34.1	36.1	38.2	40.3
55	Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
56	Debt Service			177.2	38.8	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9	57.9
57	Ending Balance			857.8	849.9	837.8	825.0	811.4	797.1	782.0	766.0	749.1	731.2	712.2	692.2	671.0	648.6	624.9	599.9	573.5
58																				

Unwind Debt

December 2007

($M)		2008H1	Transaction	2008H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Unwind Allocation		0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
Pre-Transaction Allocation		0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
59 Supporting Schedules		0.000	0.000	0.669	1.669	2.669	3.669	4.669	5.669	6.669	7.669	8.669	9.669	10.669	11.669	12.669	13.669	14.669	15.669
60 Amortization of Financing Costs																			
61 Fixed/ Insured (Tranche 1)																			
62 Net Borrowing and YTM	5.92%		(174.5)	6.9	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2	10.2
63 BB			-	174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6
64 YTM			-	6.9	10.3	10.3	10.3	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4	10.4
65 Principal Amort.			(181.5)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66 Accretion			-	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2
67 EB			174.5	174.6	174.6	174.7	174.8	175.0	175.1	175.2	175.3	175.5	175.7	175.8	176.0	176.2	176.4	176.6	176.8
68																			
69 Fixed/ Insured (Tranche 2)																			
70 Net Borrowing and YTM	5.82%		(79.4)	3.0	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	5.2	42.5	42.5
71 BB			-	79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2
72 YTM			-	3.1	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	4.6	2.3
73 Principal Amort.			(82.0)	-	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.8	38.2	40.3
74 Accretion			-	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.1
75 EB			79.4	79.4	79.4	79.3	79.3	79.3	79.2	79.1	79.1	79.0	79.0	78.9	78.8	78.8	78.2	40.2	0.0
76																			
77 Variable																			
78 Net Borrowing and YTM	0.00%		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
79 BB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
80 YTM			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
81 Principal Amort.			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
82 Accretion			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
83 EB			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
84																			
85																			
86 Amortization of Financing Costs																			
87 Deferred debit - BOY			9.6	9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0
88 Amortization			-	0.1	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.4	0.4	0.4	0.4	0.3
89 Deferred debit - EOY			9.6	9.5	9.3	9.1	8.8	8.5	8.3	8.0	7.7	7.4	7.0	6.7	6.3	5.9	5.5	5.0	4.7
90																			
91 Interest Expense																			
92 Total Interest			-	26.8	39.6	38.5	37.4	36.2	34.9	33.6	32.2	30.7	29.1	27.4	25.6	23.8	21.8	19.7	17.6
93 ARVP Accretion			-	4.0	6.2	6.6	7.0	7.4	7.9	8.3	8.8	9.3	9.9	10.5	11.1	11.7	12.4	13.2	14.0
94 Capitalized Interest			-	(0.5)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)	(0.8)
95 AMBAC Amortization (PCB) A/C 165			-	0.3	0.4	0.4	0.4	0.4	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	-
96 Line of Credit Fee			-	0.3	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
97 Total			-	31.0	45.9	45.2	44.4	43.7	42.7	41.8	40.8	39.9	38.8	37.7	36.6	35.4	34.1	32.7	31.2

Sale Leaseback

December 2007

	($M)	2007	2008H1	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	BOY Deferred Gain	56.4	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2
2	Amortization (I/S)	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
3	EOY Deferred Gain (B/S)	53.5	52.5	50.6	47.8	45.0	42.2	39.3	36.5	33.6	30.7	27.8	24.9	22.0	19.1	16.1	13.2	10.2	7.2
4																			
5																			
6	Investment - Special Deposit (B/S)	192.9	195.1	199.6	200.7	209.0	217.7	226.0	234.9	244.5	254.7	265.6	277.4	290.0	303.4	317.8	333.3	349.8	367.6
7	Adder	0.7	0.2	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
8	Balance Sheet	193.7	195.4	200.4	201.5	209.8	218.4	226.7	235.7	245.2	255.4	266.4	278.1	290.7	304.2	318.6	334.0	350.6	368.3
9																			
10	Liability - Long-Term Debt (B/S)	183.9	186.2	190.9	192.4	201.0	210.0	218.7	228.1	238.0	248.7	260.1	272.4	285.5	299.5	314.5	330.5	347.7	366.1
11																			
12	*Cash Flow (Investment and Liability)*	6.2	2.1	4.2	11.9	5.3	5.5	6.4	6.4	6.4	6.4	6.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3
13																			
14	True Unrecognized Gain	(44.4)	(43.6)	(41.9)	(39.4)	(37.0)	(34.5)	(32.1)	(29.6)	(27.2)	(24.8)	(22.3)	(19.9)	(17.5)	(15.1)	(12.8)	(10.4)	(8.0)	(5.7)
15																			
16	Sale-Leaseback Interest Income	12.5	4.3	8.7	13.0	13.6	14.1	14.7	15.3	15.9	16.6	17.3	18.1	18.9	19.8	20.8	21.8	22.9	24.1
17																			
18	Sale-Leaseback Interest Expense	12.8	4.4	8.9	13.3	13.9	14.5	15.1	15.7	16.3	17.0	17.8	18.6	19.4	20.3	21.3	22.4	23.5	24.7
19	Sale-Leaseback Gain Amortization	2.9	1.0	2.0	2.8	2.8	2.8	2.8	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.0	3.0	3.0	3.0
20	Net Sale-Leaseback Expense	9.9	3.4	6.9	10.6	11.1	11.7	12.2	12.8	13.5	14.2	14.9	15.7	16.5	17.4	18.4	19.4	20.5	21.7
21																			
22	Net Sale-Leaseback Income	2.6	0.8	1.7	2.4	2.5	2.5	2.5	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4	2.4
23																			
24	Sale-Leaseback - LeaseCo.																		
25	Defeasance Income	64.5	21.3	64.9	61.3	62.1	62.9	63.1	63.4	63.6	63.9	64.1	64.4	64.7	65.1	65.4	65.8	66.2	66.6
26	Rent Expense	(48.9)	(16.2)	(48.9)	(48.9)	(48.9)	(48.9)	(50.6)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)	(59.7)
27	Net	15.6	5.2	16.0	12.4	13.2	14.1	12.5	3.6	3.9	4.1	4.4	4.7	5.0	5.3	5.7	6.1	6.5	6.9

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1	**Summary**																			
2	Income Tax Expense	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
3	Income Taxes Paid	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
4	Current Provision for Deferred Income Tax	(0.9)	(0.1)	(1.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
5																				
6	**Calculation**																			
7	Offsystem Sales	64.9	26.9	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	Interest Earnings	-	-	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
9	Nonpatronage Revenues	64.9	26.9	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
10	Nonpatronage Expenses																			
11	Nonpatronage MWH	25.7%	39.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	-	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
12	Nonpatronage Expenses (Ex. Int.)	38.2	23.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Nonpatronage Interest Expense	15.4	7.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Nonpatronage Net Margin (pre-tax)	11.3	(3.9)	-	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
15																				
16	Transaction Impact	-	-	55.8	-	-														
17																				
18																				
19	Temporary Differences (Timing)																			
20	Depreciation:																			
21	Prorated from Pre-Transaction Model	6.1	3.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	Effect of Additional Capex (Incl. Coleman Scrubber)	(1.4)	(0.8)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
23	Other Ms	0.3	0.1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
24	Sale-Leaseback																			
25	Defeasance Income	64.5	8.4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
26	Rent Expense	(48.9)	(6.4)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
27	Other Interest Allocation																			
28	Net	15.6	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
29	Total	20.5	4.5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
30	Taxable Income before NOLs	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
31																				
32	Regular Tax																			
33	Regular NOLs Used	31.8	0.6	55.8	1.0	1.5	1.6	1.7	1.7	0.0	-	-	-	-	-	-	-	-	-	-
34	Taxable Income after NOLs	-	-	-	-	-	-	-	-	1.8	1.9	2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.7	2.8
35	Regular Tax before Min. Credit Carryover	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0
36	AMT Offset (Min. Tax Credit Carryover Utilized)	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
37	Tax	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
38																				
39	AMT																			
40	ACE Adjustment	(0.9)	(0.3)	-	(0.6)	(0.9)	(0.9)	(0.6)	(0.4)	(0.4)	(0.3)	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
41	Taxable Income	30.9	0.3	55.8	0.4	0.6	0.7	1.1	1.3	1.4	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
42	AMT NOLs Used	27.8	0.3	50.2	0.3	0.6	0.7	1.0	1.2	1.3	-	-	-	-	-	-	-	-	-	-
43	Net Taxable Income	3.1	0.0	5.6	0.0	0.1	0.1	0.1	0.1	0.1	1.6	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.7	2.8
44	TMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
45	Less Regular Tax Paid (up to AMT)	-	-	-	-	-	-	-	-	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
46	Net AMT	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
47	AMT Balance																			
48	BB	4.7	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2
49	Additions	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	-	-	-	-	-	-	-	-	-	-	-
50	Reductions	-	-	-	-	-	-	-	-	0.6	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4
51	EB	5.6	5.7	6.8	6.8	6.8	6.9	6.9	6.9	6.3	6.0	5.6	5.3	5.0	4.7	4.3	3.9	3.6	3.2	2.7
52																				
53	Total Tax	0.9	0.1	1.1	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6
54																				
55	Est. Book Tax	-	-	-	-	-	-	-	-	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.9	0.9	0.9	1.0

Income Taxes

	($M)	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Transaction Index	0.000	0.000	1.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
56																				
57	Capex Not Reflected in Pre-Transaction Tax Calculation																			
58																				
59	WKE Share																			
60	Non-Incremental	0.5	0.5	-	0.5	0.5	0.5	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
61	Incremental	0.8	0.8	-	0.8	0.8	0.8	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
62	Capex Amounts																			
63	Non-Incremental	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
64	Incremental Generation		-																	
65	WKE Total	6.8	7.1	-	7.4	16.6	12.1	17.2	19.9	20.1	20.7	21.3	21.9	22.6	23.3	24.0	24.7	25.4	26.2	27.0
66	Plant Maintenance	-	-	-	5.7	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
67	Environmental	-	-	-	2.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
68	Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
69	Shared HQ Building	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Intellectual Property	-	-	-	4.5	5.4	1.7	1.2	2.9	1.6	1.3	3.0	1.4	1.4	3.6	1.5	1.5	3.4	1.6	2.1
71	8/07 Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Total	11.0	7.1	-	23.2	49.2	36.4	38.8	36.3	23.3	25.0	24.3	23.3	24.0	28.7	29.6	27.1	28.8	27.8	29.0
73																				
74	Cumulative Balance	167.5	174.6	174.6	197.9	247.0	283.4	322.3	358.6	381.9	406.8	431.2	454.5	478.4	507.1	536.7	563.7	592.5	620.2	649.3
75																				
76	Book Depreciation @ 60 Years	2.8	1.0	-	3.3	4.1	4.7	5.4	6.0	6.4	6.8	7.2	7.6	8.0	8.5	8.9	9.4	9.9	10.3	10.8
77																				
78	Tax Depreciation @ 20 Years	8.4	2.9	-	9.9	12.4	14.2	16.1	17.9	19.1	20.3	21.6	22.7	23.9	25.4	26.8	28.2	29.6	31.0	32.5
79																				
80	Timing Difference (Tax Deduction)	(5.6)	(1.9)	-	(6.6)	(8.2)	(9.4)	(10.7)	(12.0)	(12.7)	(13.6)	(14.4)	(15.1)	(15.9)	(16.9)	(17.9)	(18.8)	(19.7)	(20.7)	(21.6)

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	(5,694,777)	(1,488,056)	0	0
1984	22,448,681	0	(11,951,703)	(10,496,978)	0	0
1985	67,286,392	0	(67,286,392)	0	0	0
1986	56,198,468	0	(56,198,468)	0	0	0
1987	75,567,924	0	(75,567,924)	0	0	0
1988	44,315,156	0	(44,315,156)	0	0	0
1989	22,819,745	0	(22,819,745)	0	0	0
1990	36,952,270	0	(34,627,493)	(2,324,777)	0	0
1991	29,446,433	0	(20,568,120)	(8,878,313)	0	0
1992	14,648,800	0	(14,648,800)	0	0	0
1993	30,220,578	0	(30,220,578)	0	0	0
1994	36,390,275	0	(36,390,275)	0	0	0
1995	43,631,999	0	(11,132,402)	(32,499,597)	0	0
1996	12,713,387	0	(1,675,643)	(11,037,744)	0	0
1997	29,946,372	0	(1,747,361)	(28,199,011)	0	0
1998	(5,694,777)	5,694,777	0	0	0	0
1999	(11,951,703)	11,951,703	0	0	0	0
2000	(211,273,153)	211,273,153	0	0	0	0
2001	(20,133,776)	20,133,776	0	0	0	0
2002	(18,036,546)	18,036,546	0	0	0	0
2003	(17,437,192)	17,437,192	0	0	0	0
2004	(14,433,689)	14,433,689	0	0	0	0
2005	(19,500,822)	19,500,822	0	0	0	0
2006	(20,568,120)	20,568,120	0	0	0	0
2007	(31,833,276)	31,833,276	0	0	0	0
2008	(627,320)	627,320	0	0	0	0
Transaction	(55,780,912)	55,780,912	0	0	0	0
2008	(1,002,760)	1,002,760	0	0	0	0
2009	(1,540,918)	1,540,918	0	0	0	0
2010	(1,606,869)	1,606,869	0	0	0	0
2011	(1,675,643)	1,675,643	0	0	0	0
2012	(1,747,361)	1,747,361	0	0	0	0
2013	(1,822,148)	0	0	0	0	0
2014	(1,900,136)	0	0	0	0	0
2015	(1,981,462)	0	0	0	0	0
2016	(2,066,268)	0	0	0	0	0
2017	(2,154,705)	0	0	0	0	0
2018	(2,246,926)	0	0	0	0	0
2019	(2,343,094)	0	0	0	0	0
2020	(2,443,379)	0	0	0	0	0
2021	(2,547,955)	0	0	0	0	0
2022	(2,657,008)	0	0	0	0	0
2023	(2,770,728)	0	0	0	0	0
Total Carryforward to 2024	69,990,667	434,844,837	(434,844,837)	(94,924,476) 185,791,428	0	0

STATEMENT 60

FEDERAL CUMULATIVE NONPATRON NET OPERATING LOSSES
TAX YEARS 1983-2023

TAX YEAR	NONPATRON TAXABLE LOSS (INCOME)	NOL UTILIZED	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	280,715,904	249,053,409	(249,053,409)	(11,985,034)	268,730,870	268,730,870
Total Carryforward to 2003	262,679,358	267,089,955	(267,089,955)	(11,985,034)	250,694,324	250,694,324
Total Carryforward to 2004	245,242,166	284,527,147	(284,527,147)	(11,985,034)	233,257,132	233,257,132
Total Carryforward to 2005	230,808,477	298,960,836	(298,960,836)	(11,985,034)	218,823,443	218,823,443
Total Carryforward to 2006	211,307,655	318,461,658	(318,461,658)	(14,309,811)	196,997,844	196,997,844
Total Carryforward to 2007	190,739,535	339,029,778	(339,029,778)	(23,188,124)	167,551,411	167,551,411
Total Carryforward to H1 2008	158,906,259	370,863,054	(370,863,054)	(23,188,124)	135,718,135	135,718,135
Total Carryforward to Transactio	158,278,939	371,490,374	(371,490,374)	(23,188,124)	135,090,815	135,090,815
Total Carryforward to H2 2008	102,498,027	427,271,286	(427,271,286)	(23,188,124)	79,309,903	79,309,903
Total Carryforward to 2009	101,495,267	428,274,046	(428,274,046)	(23,188,124)	78,307,143	78,307,143
Total Carryforward to 2010	99,954,349	429,814,964	(429,814,964)	(23,188,124)	76,766,225	76,766,225
Total Carryforward to 2011	98,347,480	431,421,833	(431,421,833)	(55,687,721)	42,659,759	42,659,759
Total Carryforward to 2012	96,671,837	433,097,476	(433,097,476)	(66,725,465)	29,946,372	29,946,372
Total Carryforward to 2013	94,924,476	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2014	93,102,328	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2015	91,202,192	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2016	89,220,730	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2017	87,154,462	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2018	84,999,757	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2019	82,752,831	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2020	80,409,737	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2021	77,966,358	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2022	75,418,402	434,844,837	(434,844,837)	(94,924,476)	0	0
Total Carryforward to 2023	72,761,394	434,844,837	(434,844,837)	(94,924,476)	0	0

- Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
  For years beginning after 8/6/97 carryback 2 years, carryforward 20.

AMT NOLs

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
1983	7,182,833	0	0	0	(7,182,833)	0	0
1984	22,448,681	0	0	0	(22,448,681)	0	0
1985	67,286,392	0	0	(67,286,392)	0	0	0
1986	56,198,468	0	0	(56,198,468)	0	0	0
1987	74,385,162	0	0	(62,522,466)	(11,862,696)	0	0
1988	44,314,663	0	0	(14,775,845)	(29,538,819)	0	0
1989	20,107,778	0	0	(12,087,111)	(8,020,667)	0	0
1990	29,346,400	0	0	(16,651,074)	(12,695,326)	0	0
1991	22,667,781	0	0	(17,624,779)	(5,043,002)	0	0
1992	9,553,735	0	0	(9,553,735)	0	0	0
1993	21,693,629	0	0	(21,693,629)	0	0	0
1994	27,573,481	0	0	(27,573,481)	0	0	0
1995	34,018,244	0	0	(21,087,586)	(12,930,658)	0	0
1996	9,443,662	0	0	(968,129)	(8,475,533)	0	0
1997	32,657,152	0	0	(1,184,282)	(31,472,870)	0	0
1998	44,897	0	0	(44,897)	0	0	0
1999	8,082,161	0	0	(1,254,439)	(6,827,722)	0	0
2000	(165,931,656)	149,338,490	(16,593,166)	0	0	0	0
2001	(19,634,252)	19,634,252	0	0	0	0	0
2002	(17,034,584)	17,034,584	0	0	0	0	0
2003	(16,417,605)	14,775,845	(1,641,761)	0	0	0	0
2004	(13,430,123)	12,087,111	(1,343,012)	0	0	0	0
2005	(18,501,193)	16,651,074	(1,850,119)	0	0	0	0
2006	(19,583,088)	17,624,779	(1,958,309)	0	0	0	0
2007	(30,915,813)	27,824,231	(3,091,581)	0	0	0	0
2008	(324,006)	291,606	(32,401)	0	0	0	0
Transaction	(55,780,912)	50,202,821	(5,578,091)	0	0	0	0
2008	(388,611)	349,750	(38,861)	0	0	0	0
2009	(647,037)	582,333	(64,704)	0	0	0	0
2010	(730,767)	657,691	(73,077)	0	0	0	0
2011	(1,075,699)	968,129	(107,570)	0	0	0	0
2012	(1,315,869)	1,184,282	(131,587)	0	0	0	0
2013	(1,443,707)	1,299,336	(144,371)	0	0	0	0
2014	(1,638,356)	0	(1,638,356)	0	0	0	0
2015	(1,883,882)	0	(1,883,882)	0	0	0	0
2016	(2,042,669)	0	(2,042,669)	0	0	0	0
2017	(2,149,181)	0	(2,149,181)	0	0	0	0
2018	(2,241,548)	0	(2,241,548)	0	0	0	0
2019	(2,337,861)	0	(2,337,861)	0	0	0	0
2020	(2,437,831)	0	(2,437,831)	0	0	0	0
2021	(2,542,573)	0	(2,542,573)	0	0	0	0
2022	(2,651,791)	0	(2,651,791)	0	0	0	0
2023	(2,765,676)	0	(2,765,676)	0	0	0	0
Total Carryforward to 2024	101,158,829	330,506,313	(55,339,977)	(330,506,313)	(156,498,806)	0	0

AMT NOLs

BIG RIVERS ELECTRIC CORPORATION & SUBSIDIARY
EIN: 61-0597287
STATEMENT 61

ALTERNATIVE MINIMUM TAX NONPATRON NET OPERATING LOSSES

TAX YEAR	AMT NONPATRON LOSS (INCOME)	NONPATRON NOL UTILIZED (90% LIMIT **)	REMAINING AMT NONPATRON (INCOME)	NONPATRON SECTION 172 USAGE	NONPATRON EXPIRED NOL'S	NONPATRON REMAINING NOL'S	TOTAL NET NOLS
Total Carryforward to 2002	301,439,211	168,972,742	(16,593,166)	(168,972,742)	(29,631,514)	288,400,863	288,400,863
Total Carryforward to 2003	284,404,627	186,007,326	(16,593,166)	(186,007,326)	(41,494,210)	259,503,583	259,503,583
Total Carryforward to 2004	267,987,022	200,783,171	(18,234,926)	(200,783,171)	(71,033,028)	215,188,920	215,188,920
Total Carryforward to 2005	254,556,899	212,870,282	(19,577,938)	(212,870,282)	(79,053,695)	195,081,142	195,081,142
Total Carryforward to 2006	236,055,706	229,521,355	(21,428,058)	(229,521,355)	(91,749,022)	165,734,742	165,734,742
Total Carryforward to 2007	216,472,618	247,146,135	(23,386,367)	(247,146,135)	(96,792,024)	143,066,961	143,066,961
Total Carryforward to H1 2008	185,556,805	274,970,366	(26,477,948)	(274,970,366)	(96,792,024)	115,242,730	115,242,730
Total Carryforward to Transacti	185,232,799	275,261,971	(26,510,348)	(275,261,971)	(96,792,024)	114,951,124	114,951,124
Total Carryforward to H2 2008	185,232,799	325,464,792	(32,088,440)	(325,464,792)	(96,792,024)	120,529,215	120,529,215
Total Carryforward to 2009	129,063,276	325,814,542	(32,127,301)	(325,814,542)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2010	128,416,240	326,396,875	(32,192,004)	(326,396,875)	(96,792,024)	FALSE	FALSE
Total Carryforward to 2011	127,685,472	327,054,566	(32,265,081)	(327,054,566)	(109,722,681)	FALSE	FALSE
Total Carryforward to 2012	126,609,773	328,022,695	(32,372,651)	(328,022,695)	(118,198,214)	FALSE	FALSE
Total Carryforward to 2013	125,293,904	329,206,977	(32,504,238)	(329,206,977)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2014	123,850,198	330,506,313	(32,648,609)	(330,506,313)	(149,671,084)	FALSE	FALSE
Total Carryforward to 2015	122,211,841	330,506,313	(34,286,965)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2016	120,327,959	330,506,313	(36,170,847)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2017	118,285,290	330,506,313	(38,213,516)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2018	116,136,109	330,506,313	(40,362,697)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2019	113,894,562	330,506,313	(42,604,244)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2020	111,556,701	330,506,313	(44,942,105)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2021	109,118,869	330,506,313	(47,379,937)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2022	106,576,296	330,506,313	(49,922,510)	(330,506,313)	(156,498,806)	0	0
Total Carryforward to 2023	103,924,506	330,506,313	(52,574,301)	(330,506,313)	(156,498,806)	0	0

* Carryback/Carryforward Rules: For years beginning before 8/6/97 carryback 5 years, carryforward 15.
For years beginning after 8/6/97 carryback 2 years, carryforward 20.

** For years ended December 31, 2001 and December 31, 2002, the Job Creation and Worker Assistance Act of 2002 allowed 100% of the AMTI to be offset with NOL carryforwards.

Inputs

December 2007

	Electricity Sales, Purchases, and Production	Source:	005/ Othe	2006	2007	2008H1	Transactio 4/30/2008	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
1	*Sales*																						
2	Rural																						
3	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls and file: annu		2.232	2.396	0.762		1.632	2.438	2.487	2.543	2.595	2.651	2.704	2.763	2.819	2.879	2.935	2.997	3.059	3.120	3.180	3.242
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%	60.02%	60.12%	60.21%	60.15%	60.40%	60.49%	60.57%	60.51%	60.74%	60.82%	60.89%	60.83%	61.04%	61.11%	61.17%
5	MW			413	425	145		310	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
6	Large Industrial																						
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691	1.063	1.097	1.131	1.165	1.200	1.235	1.269	1.303	1.338	1.373	1.407	1.440	1.476	1.510	1.545
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%	78.65%	78.65%	78.65%	78.39%	78.65%	78.65%	78.65%	78.36%	78.65%	78.65%	78.65%	78.33%	78.65%	78.65%	78.65%
9	MW			140	139	47		101	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
10	Alcan																						
11	TWH	*Smelter Retail Agreement*, Section 1.1.17			0	0		2.109	3.142	3.142	-	-	-	-	-	-	-	-	-	-	-	-	-
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366	366	366	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Century																						
15	TWH	Smelter Retail Agreement, Section 1.1.16				-		2.789	4.155	4.155	-	-	-	-	-	-	-	-	-	-	-	-	-
16	LF	*Smelter Retail Agreement*, Section 1.1.16			98.00%	98.00%		98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%	98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484	484	484	-	-	-	-	-	-	-	-	-	-	-	-	-
18																							
19	Offsystem (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		1.93	1.16	0.71		1.06	1.49	1.61	7.90	8.04	7.84	8.08	7.93	7.77	7.27	7.71	7.24	7.33	7.27	7.23	7.22
20																							
21	*Purchases & Production*																						
22	Purchases (TWh)																						
23	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		0.07	0.02	0.01		0.13	0.29	0.19	0.00	-	0.00	-	-	-	0.01	-	0.00	-	0.00	0.00	-
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17	0.30	0.31	0.31	0.30	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27
25	Production (TWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		8.07	11.80	12.10	11.31	11.53	11.47	11.80	11.74	11.67	11.26	11.80	11.43	11.61	11.65	11.70	11.79
26	*Loss Rate (%)*	file: annual output - 2-5-08 - No Smelters after 2010.xls			0.81%	0.81%		0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%	0.81%
27																							
28	Fuel Consumption (MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						89.9	131.5	134.0	125.3	127.4	126.1	129.7	129.0	128.1	123.9	129.8	125.7	127.8	128.1	128.6	129.7
29																							
30	Startup Costs (M$)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4.38	6.64	6.84	7.06	6.35	6.39	6.96	6.10	6.62	7.78	6.80	8.60	7.90	7.35	8.13	8.18
31																							
32	Emissions																						
33	SO2																						
34	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		14,032	18,797	19,882	18,354	19,098	18,060	19,229	18,959	19,263	17,802	19,391	18,577	19,090	18,763	19,247	18,922
35	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		32,653	48,979	24,489	24,489	24,489	24,489	24,489	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125	17,125
36	NOX																						
37	Emitted (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,932	13,610	13,606	12,599	12,680	12,861	12,837	12,932	12,634	12,608	12,823	12,600	12,824	12,840	12,672	13,095
38	Allocation (Tons)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	-		4,651	11,072	11,072	11,072	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)				-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
40																							
41	Rates																						
42	Fuel ($/ MMBtu)	file: annual output - 2-5-08 - No Smelters after 2010.xls						1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
43	Power Purchases ($/ MWh)																						
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44	22.44	22.44	22.44	28.33	29.04	29.75	29.75	29.75	29.75	30.50	31.24	31.24	31.24	31.24	32.00
45	Market	file: annual output - 2-5-08 - No Smelters after 2010.xls		67.8347	77.90	200.00		47.55	53.53	53.88	43.50	0.98	47.31	1.35	1.51	1.58	48.36	2.01	56.31	2.09	50.55	44.15	2.76
46	*Variable Production ($/ MWh sales)*	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	2.27		2.27	2.45	2.60	2.84	3.06	3.14	3.18	3.54	3.64	3.75	3.81	3.90	4.01	4.19	4.22	4.38
47	SO2 Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	778		778	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls			-	763		763	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
49																							
50	Coal used (ktons)	file: annual output - 2-5-08 - No Smelters after 2010.xls	100%					4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,851	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
51																							
52	**Sales Rates & Related**																						
53																							
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02																			
56	Market ($/ MWh)	file: annual output - 2-5-08 - No Smelters after 2010.xls		43.30	42.91	37.82		48.40	51.34	49.47	52.61	52.37	52.20	52.64	53.80	53.69	53.68	55.70	55.79	58.50	59.08	61.62	63.02
57																							
58	Rural																						
59	Demand ($/ KW-mo.)	Current Member Tariff		7.37	Escalated by GRAs																		
60	Energy ($/ MWh)	Current Member Tariff		20.4	Escalated by GRAs																		
61																							
62	Large Industrial																						
63	Demand ($/ KW-mo.)	Current Member Tariff		10.15	Escalated by GRAs																		
64	Energy ($/ MWh)	Current Member Tariff		13.715	Escalated by GRAs																		
65																							
66	*Smelters*																						
67	Margin ($/ MWh)	Smelter Retail Agreements, Section 1.1.20 (*Alcan*) and *1.1.19 (Century)*						0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formule in Smelter Rate Structure, lines 99 - 127)						0.00	-	0.00	40.39	42.51	43.22	43.69	46.46	46.71	50.93	47.90	51.41	51.12	53.51	52.89	55.16
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11	5.11	5.11	-	-	-	-	-	-	-	-	-	-	-	-	-
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20	0.72	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20	1.20
71	Base Fixed Energy	line 11 + line 15						4.90	7.30	7.30	-	-	-	-	-	-	-	-	-	-	-	-	-
72	Surcharge 2 (M$)	line 70 * line 71						5.88	5.22	8.76	-	-	-	-	-	-	-	-	-	-	-	-	-
73																							
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback ransaction		3.68	3.68000	1.21661		2.46	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68	3.68
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74	0.73	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.71
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
77																							
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						0.41	1.38	2.37	-	-	-	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.15	0.52	0.91	-	-	-	-	-	-	-	-	-	-	-	-	-
80	TIER Rebate Related to Smelters ($M)	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						1.18	3.95	6.67	-	-	-	-	-	-	-	-	-	-	-	-	-
81	FAC Base, 12/2004 ($/ MWh Sold)																						
82	W/o Purchased Power (Total Sales Denom.)	*Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0*	10.72																				
83	W/ Purchased Power (Total Sales Denom.)	Updated Model Results - 12-3-20041BCY ADJ 6mo-12-0	12.47																				
84	Allocation of Revenues on '																						
85	Total																						
86	*NOx + SO3*	file: annual output - 2-5-08 - No Smelters after 2010.xls																					
87	VOM	file: annual output - 2-5-08 - No Smelters *after 2010.xls*						0.99	3.30	3.74	3.56	3.80	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
88	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	6.72	7.41	7.81	7.90	8.67
89	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
90	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
91	Net Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
92	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
93	Allowed In ES																						
94	NOx + SO3	*file: annual output - 2-5-08 - No Smelters after 2010.xls*																					
95	VOM	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.99	3.30	3.74	3.56	3.60	3.62	4.10	4.09	4.38	4.01	4.63	4.49	4.72	4.86	5.17	5.05
96	Allowances	file: annual output - 2-5-08 - No Smelters after 2010.xls						0.21	7.23	6.10	3.29	3.22	3.43	3.40	7.45	6.45	6.69	7.10	6.72	7.41	7.81	7.90	8.67
97	SO2	file: annual output - 2-5-08 - No Smelters after 2010.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
98	VOM in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						17.35	25.66	27.66	28.51	31.51	32.37	33.47	37.46	38.14	38.24	40.30	40.05	41.82	43.95	44.22	46.58
99	Net Allowance Costs in Excess of 2009	file: annual output - 2-5-08 - No Smelters after 2010.xls						(14.49)	(25.74)	(4.06)	(5.02)	(4.27)	(4.80)	(4.14)	1.66	1.62	0.42	0.81	0.21	0.27	0.22	0.24	0.19
100	Total	file: annual output - 2-5-08 - No Smelters after 2010.xls						4.06	10.44	33.45	30.34	34.27	34.61	36.82	50.67	50.60	49.35	52.84	51.47	54.22	56.84	57.53	60.49
101																							
102	Smelter Rate Structure																						
103	Bandwidth	Smelter Retail Agreements, Section 4.7.1						2.20	2.20	2.20	2.20	3.20	3.20	3.20	3.80	3.80	3.80	4.40	4.40	4.40	5.00	5.00	5.00
104																							
105																							
106	**Financing**																						
107																							
108	Principal Schedules																						
109	Fixed/ Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
110	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.20%	0.21%	0.22%	0.23%	0.25%	0.26%	0.27%	0.29%	0.30%	0.32%	0.33%	0.35%	0.96%	46.62%	49.18%
111	RUS	Modeled for 30-Year Debt Levelization/ Cost Minimization						3.39%	5.21%	5.51%	5.82%	6.16%	6.51%	6.89%	7.28%	7.70%	8.14%	8.61%	9.11%	9.63%	10.05%	0.00%	0.00%
112	Variable	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
113	PCB (Swapped to Fixed)	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
114	ARVP	Modeled for 30-Year Debt Levelization/ Cost Minimization						0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
115																							
116	Rates																						
117	Fixed/ Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						5.50%	5.42%	5.34%	5.26%	5.18%	5.21%	5.24%	5.26%	5.29%	5.32%	5.35%	5.39%	5.42%	5.45%	5.48%	5.52%
119	RUS -- Stated	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%	5.75%
120	Variable	NA						5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%	5.45%
121	PCB (Swapped to Fixed/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007 xls						3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%	3.60%
122	ARVP (Accretion/ Refi)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls	0.059144					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
123	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls						5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%	5.82%
124																							
125	Beginning Balances (M$)																						
126	Fixed/ Insured	Modeled for 30-Year Debt Levelization					181																
127	Fixed/ Non-Insured	Modeled for 30-Year Debt Levelization					82																
128	Variable	NA					-																
129	PCB	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Levelization					142																
130	ARVP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls + Modeling for 30-Year Debt Les				249.89	102																
131	RUS -- GAAP	Long Term Debt Schedule Actual 2006 - Budget 2007.xls					351																
132	Remarketing on Variable	NA	0.25%																				
133																							
134	Fees																						
135	Underwriting & Other	Goldman Sachs verbal guidance.	1.75%																				
136	Bond Insurance	Goldman Sachs verbal guidance.	0.80%																				
137																							
138	Capitalized Interest	Big Rivers' estimate		(0.24)	(0.73)	(0.24)		(0.48)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)	(0.84)
139	Deferred Debit - PCB Refunding A/C 181																						
140	Beginning Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.90	0.84	0.79	0.77	0.77	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-
141	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.05	0.05	0.02	-	0.04	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	-
142	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.84	0.790	0.772	0.772	0.74	0.68	0.63	0.58	0.52	0.47	0.42	0.37	0.31	0.26	0.21	0.15	0.10	0.05	-	-
143	AMBAC Amortization (PCB) A/C 165																						
144	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.42	0.42	0.14	-	0.28	0.42	0.42	0.42	0.42	0.30	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.16	-
145	Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		4.69	4.27	4.13	4.13	3.85	3.43	3.00	2.56	2.16	1.86	1.65	1.44	1.22	1.01	0.80	0.59	0.37	0.16	-	-
146	Settlement Note/Marketing Payment																						
147	Amortization	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.00	1.00	0.33	-	0.67	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
148	Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		17.08	16.07	15.74	15.74	15.07	14.06	13.06	12.06	11.05	10.05	9.04	8.04	7.04	6.03	5.03	4.02	3.02	2.02	1.01	-
149	Green River Coal Settlement Ending Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.09	0.05	0.03	0.03	0.00	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
150	Other			(0.21)	(0.34)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)	(0.44)
151	Line of Credit	Big Rivers' estimate	0.50%	100.00																			
152	Prepayment on Transaction Date	Modeled to achieve target cash balances		-	-	-	185.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
153	Pre-Transaction Debt Service																						
154	Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		26.43	12.47	13.05																	
155	Interest (Cash Flow)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		36.93	36.724	16.944																	
156	Interest (Income Statement)	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		60.72	59.98	19.27																	
157	Amortization of RUS/PCB Account	*Straightline amortization of RUS and PCB restructuring costs*				-	1.75	1.67	1.54	1.41	1.28	1.15	3.64	3.37	3.10	2.82	2.55	2.28	2.00	1.73	1.46	4.26	3.79
158	NEW RUS NOTE (Stated)																						
159																							
160	Beginning Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		812.23	803.60	807.60	794.71	352.00	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.48	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	13.55	19.55	18.50	17.39	16.21	14.96	13.64	12.25	10.78	9.22	7.57	5.83	3.98	2.03	-	-
164	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.16	7.32	6.98	7.15																
165	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		22.91	11.50	12.89	-	11.93	18.33	19.38	20.50	21.67	22.92	24.24	25.63	27.11	28.66	30.31	32.06	33.90	35.36	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	340.07	321.74	302.36	281.86	260.19	237.27	213.03	187.40	160.29	131.63	101.32	69.26	35.36	-	-	-
167	Orig Scheduled Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		24.00	26.00	34.00	34.00																
168	Original Maximum Allowed Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		938.60	912.60	878.61	878.61																
169																							
170	New RUS Promissory Note (GAAP)																						
171	Beginning Principal - RUS New Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		815.30	807.04	811.56	798.62	798.62															
172	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		46.21	47.16	15.05	-	30.48															
173	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		32.29	31.24	15.23	-	30.83															
174	Accrued Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		7.25	7.41	7.24	7.24	6.89															
175	Principal Payment	Long Term Debt Schedule Actual 2006 - Budget 2007 xls		22.19	11.41	12.77	-	25.85															
176	Principal Balance	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		799.79	804.14	791.38	791.38	765.53															
177	Imputed Interest	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.00	0.00	-	-	0.00															
178																							
179	**Receipts (M$)**																						
180																							

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
181	WKEC Lease	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.89	47.97	15.79		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
182	Transmission	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.95	5.15	1.70		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
183	Smelter - Tier 3 Transmission (Cash Flow)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.70	1.74	0.58		1.20	1.74	1.74	4.42	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
184	Smelter - Tier 3 Transmission (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.78	1.82	0.60		1.22	1.82	1.82	4.45	5.43	2.85	2.72	2.58	2.59	2.41	2.24	2.04	1.94	1.70	1.42	1.14
185	Proceeds of Unwind Transaction (LG&E Payment)	*Termination Agreement*		-	-	-	301.50	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
186	Cobank Patronage Capital & Other	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.57	0.53	0.18	(0.26)	0.36	0.54	0.51	0.52	0.53	0.53	0.53	0.54	0.54	0.54	0.54	0.54	0.55	0.55	0.55	0.55
187	Interest Earnings	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		3.73	6.59	1.96																	
188	Net Conformring Receipts	Big Rivers' estimate		-	15.00	-																	
189	Cobank Patronage Capital - Balance Sheet	Historic results and adapted from 2007 Budget-REVISED	2.19	2.59	2.97	3.10	3.36	3.36	3.75	4.11	4.48	4.84	5.21	5.57	5.92	6.28	6.63	6.97	7.32	7.66	7.99	8.32	8.64
190	*Lease Related & Other*	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.04	5.35	2.02		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
191	Cobank Patronage Capital (Income Statement)	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.96	0.92	0.31		0.62	0.93	0.88	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.89	0.88	0.88	0.88	0.87
192																							
193																							
194	**Fixed Production (M$)**																						
195																							
196	Fixed O&M																						
197	Non-Labor (Real)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	2008 Fact	66.7%				27.54	33.83	36.48	36.13	33.21	40.91	33.06	40.91	33.85	34.05	37.77	37.00	36.07	38.78	33.06	41.00
198	Labor (Nominal)	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
199	Plant Maintenance (Real Basis)																						
200	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.58	0.24	0.24	-	-	-	-	-	-	-	-	-	-	-	-
201	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	-	-	-	-	-	-	2.58	-	-	-	-	-	-
202	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
203	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.34	-	-	-	-	-	-	-	0.87	-	-	-	-	-	-
204	Wilson	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
205	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	0.10	0.07	0.19	0.20	0.20	0.20	1.56	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
206	Fixed Environmental O&M, Clear Skies (Real Basis)																						
207	*NOx ongoing*	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
208	Adjust for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
209	Non-Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
210	Production			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
211	Transition			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
212	O&M (Includes Consultants)			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
213	Outsource to LG&E for 2006			0	-			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
214	Adjustment (8/2007)			0.3				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
215																							
216	T/G Overhauls (Cash Flows)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
217	T/G Overhauls (Income Statement)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						2.84	9.17	-	9.25	10.46	-	6.95	-	6.74	19.80	-	13.46	5.91	7.82	8.44	-
218																							
219	Environmental Monitoring and Other		0																				
220	WKE "incremental" items moved to O&M																						
221	W-1 stack repair	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
222	boiler waterwall metal overlays	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
223	SCR catalyst replacement	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
224	Transmission O&M																						
225	Baseline Labor (06 and 07 labor & non-labor combine	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls		6.59	7.38	1.89		3.83	5.89	6.07	6.25	6.44	6.63	6.83	7.03	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
226	Baseline Non-Labor	2005 actual escalated @ 3% plus 100K				0.52		1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
227	Upgrades, Phase I (Real Basis)																						
228	O&M	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.08		0.16	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
229	*Property Tax*	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.01		0.02	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
230	Property Ins.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		-	-	0.00		0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
231																							
232	A&G																						
233	Labor	Unwind Staffing_Rev0707_Reflects 2008 Dollars_Rev 1.xls						7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
234	Non-Labor	2004 actual escalated @ 3%						6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
235	Intellectual Property *(Nominal Basis)*	*Unwind spreadsheet -- 8-29-07_Rev1.xls*						3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
236	Intellectual Property Contingency							-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
237	Total			13.81	13.80	4.86		17.85	24.97	24.21	24.97	25.37	26.13	27.25	27.72	28.55	29.77	30.29	31.20	32.51	33.10	34.09	35.51
238																							
239	APM, L/C, Cogen, CW & TVA Trans	Existing Transecion -Budget-Arb-2008-Rev9-11-07.xls		4.66	3.83	3.63		3.46	5.29	5.41	4.72	4.58	4.72	4.86	5.01	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
240																							
241	Property Insurance	2004 actual escalated @ 3%		0.40	0.40	0.14		2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
242																							
243	Property Tax			3.94	3.94	-																	
244	Baseline	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.10	1.08	0.37		1.18	1.81	1.87	2.39	2.92	3.01	3.10	3.19	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
245	Transmission -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.74	0.77	0.26		0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
246	General Plant -- Operations	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.11	0.04		0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
247																							
248																							
249	**Capital Expenditures**																						
250																							
251	*Generation*			13.12	13.41	13.95																	
252	Baseline (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls	08 Factor:	0.61				22.41	29.76	21.09	24.84	25.17	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68	24.68
253	Adjustment for Station 2 (Real Basis 2006)	file: Fin Model inputs BREC Nov-07 w outage shift.xls						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
254																							
255	Gross Incremental			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
256																							
257	Transmission (Nominal)	*Per Crockett Memo dated 11/12/07*		5.91	9.62	5.19		6.21	9.56	9.19	4.43	5.91	0.46	0.36	0.49	1.58	2.81	3.36	3.46	3.56	3.67	3.78	3.89
258																							
259	A&G (Nominal)	$1.25M 2007 escalated @ 3%		0.86	1.25	0.43		0.86	1.33	1.37	1.41	1.45	1.49	1.54	1.59	1.63	1.68	1.73	1.78	1.84	1.89	1.95	2.01
260																							
261	WKE Share of Generation Capex	Participation Agreement - Cost Sharing		51%	51%	84%		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
262																							
263	Plant Maintenance (Real Basis 2007)																						
264	Coleman	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.20	1.14	1.11	2.59	1.05	-	-	-	-	-	-	-	-	-	-	-
265	Green	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	8.55	6.75	4.23	2.29	1.32	-	-	-	-	-	-	-	-	-	-
266	HMP&L	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		1.46	1.33	0.85	6.21	3.94	-	3.49	-	-	-	-	0.89	0.88	-	-	-
267	Reid	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	1.03	-	-	-	-	-	-	-	-	1.28	-	-	-	-	-
268	Wilson	*file: Fin Model inputs BREC Nov-07 w outage shift.xls*		-	-	-		4.45	7.81	10.08	6.48	5.36	-	-	-	-	-	-	2.17	-	-	-	-
269	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		0.44	0.41	0.26	1.89	1.28	-	1.12	-	-	-	-	0.28	0.28	-	-	-
270																							
271	Plant Maintenance Claim Amount			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		Source:	2005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
272																							
273	Environmental (Real Basis 2006)																						
274	NOx Removal Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
275	Mercury Monitoring	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		3.02	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
276	*Cimn* FGD Equipment Capital	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
277	FGD ongoing upkeep capital (0.10%)	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
278	Additional FGD thickener & filler drum	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
279	R-CT reliability study & upgrades	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
280	*Wilson super healer tubes replacment*	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
281	Adjustment for Station 2	file: Fin Model inputs BREC Nov-07 w outage shift.xls		-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
282																							
283	Transmission Upgrades																						
284	*Phase I*	Per Crockett Memo dated 11/12/07		-	4.00	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
285	Phase II	Per Crockett Memo dated 11/12/07		-	-			*3.70*	*5.80*	*1.60*	-	-	-	-	-	-	-	-	-	-	-	-	-
286																							
287	Shared HQ Building																						
288	Phase I			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
289	Phase II			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
290																							
291	Intellectual Property																						
292	Capex Purposes	Unwind spreadsheet -- 8-29-07_Rev1.xls		-	-	-		4.45	5.36	1.73	1.20	2.85	1.61	1.30	3.02	1.40	1.37	3.57	1.54	1.48	3.35	1.58	2.06
293	Depreciation Purposes	Depreciated at Average Capital Depreciation Rate		-				0.07	0.16	0.19	0.34	0.41	0.45	0.49	0.57	0.60	0.64	0.73	0.77	0.81	0.90	0.94	1.00
294	Trial Balance Adjust		101.0%																				
295																							
296	Cash Adder			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
297																							
298	**Other Disbursements (M$)**																						
299																							
300	PPA	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		98.00	87.89	34.07																	
301	Environmental	*Historic results and adapted from 2007 Budget-REVISED-MARCH 2*		0.41	0.68	0.25																	
302	PCB Restructuring	Proforma transaction and bond insurance costs		-	-	-		-	-	-	-	-	2.77	-	-	-	-	-	-	-	-	3.28	-
303	LEM Settlement Note	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		1.82	1.82	0.60		1.22	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.82	1.06
304	'Other Deductions'	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.14	0.12	0.08		(1.22)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.82)	(1.06)
305	Transition Costs			-	-	-																	
306	Deferred Debit - PCB Refunding A/C 181	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		(0.05)	(0.05)	(0.02)		(0.04)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	(0.05)	*(0.05)*	*(0.05)*	*(0.05)*	*(0.05)*	*(0.05)*	*(0.05)*	*(0.05)*	-
307	Green River Coal Settlement	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		0.35	0.05	0.01		0.03	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
308	MISO Credit Fee		1	-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
309	Deferred Tax Asset Write-Down			-	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
310	Payment to City of Henderson	file: annual output - 2-5-08 - No Smelters after 2010.xls		-			-	0.19	0.31	0.31	0.31	0.33	0.33	*0.33*	*0.33*	*0.33*	*0.33*	*0.33*	0.33	*0.33*	0.33	0.33	0.33
311	Smelter Payment (Assurances Agreement)	Coordination Agreement		-	-	-	4.26	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
312	Lease-Equity Consent Fees/ Smelter Exit			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
313	Non-Smelter Member *Excess Cash Rebate*			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
314	Economic Reserve			-	-	-	75.00	(5.54)	(12.52)	(19.11)	(34.89)	*(13.32)*	-	-	-	-	-	-	-	-	-	-	-
315	Working Capital Adj.	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.09	0.21	0.02																	
316	CoBank Patronage Capital	Historic results and adapted from 2007 Budget-REVISED	2.25	2.64	3.03	3.16		3.42	3.81	4.17	4.53	4.90	5.26	5.62	5.98	6.33	6.68	7.03	7.37	7.71	8.05	8.38	8.70
317	*Amortization of RUS/PCB Charges*	*Straightline amortization of RUS and PCB restructuring costs*					-	0.09	0.13	0.13	0.13	0.13	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.27	0.47	0.47
318	**Other Assumptions**																						
319																							
320	Interest Earnings Rate on Cash Balances	Big Rivers estimate	4.28%																				
321																							
322	Inflation	Big Rivers estimate	3.00%																				
323																							
324	Receivables (days)	Big Rivers estimate	30.00																				
325																							
326	Payables (days)	Big Rivers estimate	52.50																				
327																							
328	Non-Patronage Taxable Allocation (Transaction)	Orrick Harrington/ Deloitte	15%																				
329																							
330	Sequestered Cash Ending Balance	Smelter Retail Agreements. *Section 1.1.119*	*35.00*		*0*																		
331																							
332																							
333	**Balance Sheet (2005)**																						
334																							
335	Assets																						
336	Property																						
337	Total Utility Plant in Service	Historic Balance Sheet	1,714.8	1,731.2	1,760.4	1,780.2																	
338	Construction in Progress	*Historic and Projected Balance Sheet*	12.7	13.1	13.1	13.1	13.1	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
339	Depreciation & Amortization	Historic Balance Sheet	798.7	826.6																			
340	Other Property	Historic Balance Sheet	184.0	190.7																			
341	Current																						
342	Cash General Funds & Special Deposits	*Historic Balance Sheet*	0.0	0.0	0.0	0.0	0.0																
343	Ending Cash Balance	Historic Balance Sheet	67.8	96.5																			
344	Accounts Receivable	Historic Balance Sheet	16.3	17.5	17.7	17.7																	
345	Fuel Stock & Related	Historic Balance Sheet	-	-																			
346	*Credit Escrow*	*Economic Reserve*	-	-	-	-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
347	Materials and Supplies Other	Historic Balance Sheet	0.7	0.8	0.8	0.8																	
348	Other Current Assets	Historic Balance Sheet	0.3	4.1	4.7	4.7	4.7																
349	Credits																						
350	*AMBAC/Credit Suisse July '93*	*Historic and Projected Balance Sheet*	5.1	4.7	4.3	4.1	4.1	3.8	3.4	3.0	2.6	2.2	1.9	1.7	1.4	1.2	1.0	0.8	0.6	0.4	0.2	-	-
351	Deferred Tax	Historic Balance Sheet	4.3																				
352	Other Deferred Debits/PCB Refunding 10/01	Historic Balance Sheet																					
353	LEM Settlement Note/Marketing Payment	Historic Balance Sheet	18.1	17.1	16.1	15.7																	
354	*Total Assets*																						
355																							
356	Liabilities																						
357	Margins & Equities	Historic Balance Sheet	(251.9)	(217.4)																			
358	*Long-Term Debt*																						
359	Existing Debt	Historic Balance Sheet	1,058.2	1,053.1	1,062.1	1,051.1																	
360	Sale-Leaseback Obligation	Historic Balance Sheet	171.0	177.3																			
361	Total Long-Term Debt																						
362	*Current & Accrued Liabilities*																						

Inputs

		Source:	2005/ Othe	2006	2007	2008H1	Transactior	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
363	Accounts Payable	Historic Balance Sheet	13.1	12.6	11.7																		
364	Taxes Accrued	Historic Balance Sheet	0.4	0.2	0.2																		
365	Deferred Revenue (Credit Escrow)																						
366	Interest Accrued	Historic Balance Sheet	7.5	7.6	7.8	7.6	0.4	0.4															
367	Other Accrued Liabilities	Historic Balance Sheet	5.9	6.0	6.2	6.3	6.3	6.4															
368	WKEC Lease (Resid. Value Obligation)*	Historic Balance Sheet		158.1																			
369	Sale-Leaseback Gain	Historic Balance Sheet																					
370	Other Deferred Credits & Century Reactive Power	Historic Balance Sheet	1.0	0.4	0.3	0.3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
371	Total Liabilities & Equity	Historic Balance Sheet																					
372																							
373	Misc included in Other Property		1																				
374																							
375																							
376	**Sale-Leaseback**																						
377																							
378	BOY Deferred Gain	Sale-Leaseback	62.12																				
379	Amortization (I/S)	Sale-Leaseback	2.86	2.88	2.90	0.97		1.96	2.76	2.79	2.83	2.84	2.85	2.87	2.88	2.89	2.91	2.92	2.94	2.95	2.97	2.99	3.01
380																							
381	Investment - Special Deposit (B/S)	Sale-Leaseback	180.65																				
382	Adder	Sale-Leaseback	0.50	0.73	0.74	0.24		0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74	0.74
383																							
384	Liability - Long-Term Debt (B/S)	Sale-Leaseback	170.95																				
385																							
386	Interest Income (I/S)	Sale-Leaseback	11.67	12.07	12.48	4.27		8.65	13.02	13.56	14.13	14.68	15.27	15.90	16.58	17.30	18.08	18.91	19.81	20.76	21.78	22.88	24.05
387	Interest Expense (I/S)	Sale-Leaseback	11.97	12.39	12.82	4.39		8.89	13.33	13.90	14.50	15.07	15.68	16.33	17.03	17.78	18.58	19.43	20.35	21.33	22.38	23.50	24.70
388																							
389	Cash Flow (Investment and Liability)	Sale-Leaseback	5.72	6.03	6.24	2.06		4.18	11.91	5.27	5.45	6.36	6.36	6.36	6.35	6.35	6.35	6.34	6.34	6.33	6.33	6.32	6.31
390																							
391	Sale-Leaseback - LeaseCo.																						
392	Defeasance Income	Sale-Leaseback	63.53	64.06	64.47	21.31		64.91	61.26	62.10	62.92	63.14	63.36	63.60	63.86	64.13	64.42	64.73	65.06	65.41	65.79	66.19	66.62
393	Rent Expense	Sale-Leaseback	(48.87)	(48.87)	(48.87)	(16.16)		(48.87)	(48.87)	(48.87)	(48.87)	(50.65)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)	(59.73)
394																							
395																							
396	**Unwind Transaction**																						
397																							
398	WKE Residual Value Obligation																						
399	WKE Gen. Capex - Cum.																						
400	Non-Incremental (RV Obligation Balance)																						
401	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		40.2	45.3	50.3	61.2	-	-	-	-	-	-	-									
402	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		6.7	6.8	11.7	-	-	-	-	-	-	-	-									
403	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		1.6	1.8	0.9	-	-	-	-	-	-	-	-									
404	Unattributed Plugs	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(145.1)																			
405	Incremental																						
406	Beginning Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		100.2	95.6	90.9	89.4	-	-	-	-	-	-	-									
407	WKE Share of Non-Incremental Capex	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		0.8	-	-	-	-	-	-	-	-	-	-									
408	Amortization of WKE Share	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		5.4	4.6	1.6	-	-	-	-	-	-	-	-									
409																							
410	LG&E Rental Income Advance																						
411	Cash Flow	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		47.9	48.0	15.8	-	-	-	-	-	-	-	-									
412	Income Statement	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		52.3	52.3	17.3	-	-	-	-	-	-	-	-									
413	Balance	Historic results and adapted from 2007 Budget-REVISED-MARCH 2		(17.3)	(13.0)	(11.4)	(11.4)	-	-	-	-	-	-	-									
414																							
415	Net WKE Obligation																						
416																							
417	Fuel & Other Inventories	Termination Agreement		-	-	-	55.0	-	-	-	-	-	-	-									
418																							
419	Coleman Scrubber Completion	Termination Agreement/ file: Coleman Scrubber.xls		-	-	-	97.5	-	-	-	-	-	-	-									
420																							
421	Cancellation of Settlement Prom. Note	Termination Agreement		-	-	-	16.0	-	-	-	-	-	-	-									
422																							
423	6. Other 3rd Party Add-ons																						
424	Smelter Payment	Smelter Coordination Agreement		-	-	-	4.3	-	-	-	-	-	-	-									
425	Consent Fees			-	-	-	-	-	-	-	-	-	-	-									
426																							
427	7. Non-Smelter Member Excess Cash Rebate			-	-	-	-	-	-	-	-	-	-	-									
428																							
429	8. Non-Smelter Member Excess Cash Rate Mitigation Account																						
430	BB						-	75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.7	2.0	0.5	-	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(12.5)	(19.1)	(34.9)	(13.3)	-	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	62.1	45.7	12.8	-	-	-	-	-	-	-	-	-	-	-	-
435																							
436	10. DSL Termination																						
437																							
438	11. LG&E Emissions Allowance																						
439	Volume (tons)	Termination Agreement					14,000																
440	Price ($/ton)	file: annual output - 2-5-08 - No Smelters after 2010.xls					778																
441																							
442	Lease Termination Payment			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
443	Assumed Make Whole to CoBank			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
444	Total Expense			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
445																							
446	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
447	Recognition of Deferred Gain on Original Lease			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
448	Lease Termination Payment from Unwind Counterparties			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
449																							
450	DSL Termination		0																				
451	PMCC Share		0																				
452	Net SLB		1																				
453	Depreciation																						

Inputs

		Source:	005/ Othe	2006	2007	2008H1	Transactio	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
454																							
455	Additional Book Depreciation																						
456	Prior year non-incremental + in service	Historic		12.83	13.12	4.43																	
457	Average of Transmission and A&G	Historic		6.38	10.88	5.29																	
458	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.02	0.02	0.02		0.02															
459	Capitalization Policy (0=longer rate)		1	2011	2.4%																		
460	Capital Depreciation Rate (excl. Environmental)	Based on 1993 Depreciation Study	38																				
461	Capital Depreciation Rate (Environmental)	Based on 1993 Depreciation Study	38																				
462																							
463																							
464	HMP&L Station Two																						
465	Prior year non-incremental	Historic		12.83	13.12	4.43																	
466	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
467																							
468	Other																						
469	Prior year	Historic		6.00	6.77	4.98																	
470	Depreciation as a Percentage of Gross PPE	Historic depreication rate		0.00	0.00	0.00		0.00															
471																							
472	Book Depreciation & Amortization																						
473	Generation																						
474	Big Rivers' Plants	Historic		25.36	25.39	8.58		26.58	9.01														
475	HMP&L Station Two	Historic		1.58	1.64	0.54		0.93	0.31														
476	Other	Historic		5.05	5.25	1.75		5.06	1.69														
477																							
478	Adjustment to Depreciation		0																				
479	9/24/07 Blended Depreciation Amount	Coordination Agreement, Section 3.10						0.019757	0.020404	0.021031	0.021553	0.021668	0.021221	0.020901	0.021226	0.021501							
480	Income Tax Related																						
481																							
482	Previously Expensed Marketing Payment	Historic		0	0	0	4.196																
483																							
484	Status Quo Depreciation	Proforma	23.69																				
485																							
486	WKE Share of Capex																						
487	Non-Incremental	Participation Agreement - Cost Sharing		51%	51%	51%		51%	51%	51%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
488	Incremental	Participation Agreement - Cost Sharing		0%	80%	80%		80%	80%	80%	60%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%	66%
489	Incremental Dep			0.80	0.00	0.00																	
490	Temporary Differences																						
491	2005 Cumulative Balance of Capex not reflected in SQ	Historic	149.87																				
492	Other Temporary Differences	Historic	19.65																				
493																							
494	NOL Related																						
495	Year			1983	1984	1984	1984	1984	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
496																							
497	Tax Rates																						
498	Regular	Big Rivers' estimate	35%																				
499	AMT	Big Rivers' estimate	20%																				
500																							
501	ACE																						
502	ACE Deduction			(1.23)	(1.22)	(0.40)	-	(0.82)	(1.19)	(1.17)	(0.80)	(0.58)	(0.50)	(0.35)	(0.13)	(0.03)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)	(0.01)
503	ACE %		75%																				
504																							
505	SQ Addition	Historic		0.41	0.89	0.13	-	0.26	0.44	0.43	0.71	1.61	0.47	0.90	1.35	1.77	2.26	4.72	5.56	6.36	6.71	6.76	7.87
506	2006 AMT BB			4.28	4.69	5.58	5.70																
507																							
508	Nonpatronage MWH	Historic	1	38%	0.256522	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
509	Offsystem Sales	Orrick Herrington/ Deloitte	PE																				
510	Interest Income on Unrestricted Cash	Orrick Herrington/ Deloitte	PE																				
511	Interest on Transition Reserve	Orrick Herrington/ Deloitte	NP																				
512	Interest on Economic Reserve	Orrick Herrington/ Deloitte	PE																				
513																							
514	Carbon Tax Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
515	Carbon Allowance Cost ($/MWh)	$7/ton charge starting in 2012, escalating $1/year						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
516	Carbon BY Allowance Cost ($/MWh)	5,073,775 tons in base year, $7/ton charge starting in 2012, escalating at $1/year						-	-	-	-	0.98	1.03	1.35	1.51	1.58	1.32	2.01	1.69	2.09	2.32	2.43	2.76

Fuel Inventory

	($M)	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	Lease Termination	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
1	Inventory Maintenance	100%																
2																		
3	Fuel Purchases ($/mmbtu)	1.48	1.48	1.50	1.64	1.65	1.71	1.80	1.83	1.83	1.85	1.88	1.89	1.93	1.95	1.96	2.00	2.02
4																		
5	Heat Value btu/ lb		11,034	11,014	11,015	11,023	11,004	11,003	11,059	11,007	11,006	11,021	11,028	11,049	11,024	11,000	11,058	11,029
6	Heat Value mmbtu/ ton		22.07	22.03	22.03	22.05	22.01	22.01	22.12	22.01	22.01	22.04	22.06	22.10	22.05	22.00	22.12	22.06
7	Coal Consumed [from PCM (000s tons)]		4,072	5,970	6,085	5,685	5,790	5,731	5,862	5,861	5,820	5,623	5,885	5,686	5,795	5,823	5,816	5,878
8	Coal Consumed (Gbtus)		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
9																		
10	***Volumes Fuel Inventory (Gbtus)***																	
11	BB	-	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
12	Fuel Purchased		89,860	131,498	134,049	125,337	127,416	126,123	129,658	129,028	128,114	123,932	129,790	125,651	127,762	128,100	128,628	129,665
13	LG&E Additions to Fuel Inventory	37,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Fuel Consumed	-	(89,860)	(131,498)	(134,049)	(125,337)	(127,416)	(126,123)	(129,658)	(129,028)	(128,114)	(123,932)	(129,790)	(125,651)	(127,762)	(128,100)	(128,628)	(129,665)
15	EB	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085	37,085
16																		
17	***$Millions***																	
18	BB	-	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2
19	Fuel Purchased	-	133.3	197.7	220.4	207.2	218.4	227.1	237.6	236.2	237.3	233.6	245.8	243.1	248.8	250.6	257.2	262.2
20	LG&E Additions to Fuel Inventory	55.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Fuel Expensed	-	(133.3)	(197.0)	(215.2)	(206.9)	(216.1)	(223.9)	(236.4)	(236.3)	(236.5)	(232.4)	(245.5)	(241.6)	(248.3)	(250.2)	(255.6)	(261.4)
22	EB	55.0	55.0	55.8	61.0	61.3	63.6	66.8	68.0	67.9	68.7	69.9	70.2	71.8	72.2	72.5	74.2	75.0

Item 134) Regarding the "Environmental Matters" and "significant financial impacts on the use of fossil fuels for power generation" referenced in the Big Rivers 2005 Annual Report to Members (Exhibit 41), please provide any documents or studies performed by or for E.ON since January 2005 which address and/or estimate costs associated with the Big Rivers generating facilities and compliance with:

a. The EPA's Clean Air Mercury Rule (CAMR);
b. The EPA's Clean Air Interstate Rule (CAIR);
c. Performance goals of the Clean Water Act Section 316(b);
d. Regulation of carbon dioxide as a pollutant under the Clean Air Act; and,
e. Any other state or federal rules likely to cause additional costs in order to meet pollution standards or otherwise comply with those rules.

Response) See E.ON response.

Witness) E.ON U.S.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 135) Identify each of the circumstances that contributed to Big Rivers filing for bankruptcy in 1996, and describe how each of those circumstances have been addressed since then or are otherwise not problematic at the current time.

Response) Please see the attached excerpt from the offering statement in the 1998 remarketing of certain Big Rivers pollution control debt, which contains a detailed description of the subject. None of the issues listed as significant factors contributing to Big Rivers' bankruptcy exist today. See response to AG data requests Items114 and 115. See also the offering statement attached as Exhibit 40 to the Application.

Witness) Michael H. Core

NOT A NEW ISSUE—BOOK ENTRY ONLY

On June 30, 1983, Mayer, Brown & Platt rendered its opinion that, as of the date thereof, interest on the Series 1983 Bonds is exempt from all then present Federal income taxes under then existing statutes, court decisions, regulations and rulings, except that such exemption does not apply with respect to any portion of the principal amount of the Series 1983 Bonds for any period during which such portion is held by a "substantial user" of the Facilities or a "related person" within the meaning of Section 103(b) of the Internal Revenue Code of 1954, as amended (the "Code"), and all then present Kentucky individual and corporate income taxes. On October 31, 1985, as bond counsel, Mudge Rose Guthrie Alexander & Ferdon rendered its opinion that, as of the date thereof, (i) under then existing statutes, regulations, rulings and court decisions, and assuming compliance with the covenant described therein, interest on the Series 1985 Bonds is exempt from then present Federal income taxes, except that such exemption does not apply with respect to any Series 1985 Bond during any period when such Bond is held by any person who, within the meaning of Section 103(b)(13) of the Code is a "substantial user" of the Facilities or a "related person" within the meaning of Section 103(b)(6)(C) of the Code, except that no opinion is expressed as to whether the interest accruing on the Series 1985 Bonds on or after the Conversion Date will be exempt from Federal taxation; and (ii) interest on the Series 1985 Bonds is exempt from all then present Kentucky personal and corporate income taxes, except that no opinion was expressed as to whether the interest accruing on the Series 1985 Bonds on or after the Conversion Date will be exempt from any Kentucky taxation. Both firms expressed no opinion regarding other federal, state or local tax consequences relating to the accrual or receipt of interest on the Bonds. On the Effective Date (as defined herein), Orrick, Herrington & Sutcliffe LLP, Bond Counsel, will render an opinion that the replacement of the existing letters of credit with the Bond Insurance Policies and the Liquidity Facilities (each as defined herein) will not adversely affect (i) the exclusion of interest on the Bonds from gross income for federal tax purposes and (ii) the exclusion of interest on the Bonds from all Kentucky personal and corporate income taxes, to the extent and subject to the conditions and limitations set forth in the initial opinions relating to the Bonds. See "TAX EXEMPTION" herein.

$58,800,000
County of Ohio, Kentucky
Pollution Control Floating Rate Demand Bonds, Series 1983
(Big Rivers Electric Corporation Project)

$83,300,000
County of Ohio, Kentucky
Variable Rate Demand Pollution Control Refunding Bonds, Series 1985
(Big Rivers Electric Corporation Project)

Dated: Series 1983 Bonds: **June 1, 1998**
Series 1985 Bonds: **July 1, 1998**

Series 1983 Bonds Due: **June 1, 2013**
Series 1985 Bonds Due: **October 1, 2015**

The Series 1983 Bonds and the Series 1985 Bonds (collectively, the "Bonds") and interest thereon are limited obligations of the County of Ohio, Kentucky (the "Issuer") payable solely out of the revenues and other security pledged by the Issuer and do not constitute an indebtedness of the Issuer within the meaning of the Constitution of the Commonwealth of Kentucky. The obligations to make payments due to the Issuer are evidenced by the Notes (as defined herein) of

Big Rivers Electric Corporation

Payment of the principal of and interest on the Series 1983 Bonds and the Series 1985 Bonds when due will be insured by two municipal bond insurance policies to be issued by Ambac Assurance Corporation (collectively, the "Bond Insurance Policies") simultaneously with the remarketing of the Bonds.

Ambac

The Bonds are being remarketed following the mandatory tender of the Bonds by the holders thereof in connection with the substitution of the outstanding letters of credit supporting the Bonds with the Bond Insurance Policies and two Standby Bond Purchase Agreements, each dated as of the Effective Date (collectively, the "Liquidity Facilities"), between Big Rivers Electric Corporation ("Big Rivers"), U.S. Bank Trust National Association, as trustee (the "Trustee"), and Credit Suisse First Boston (the "Liquidity Provider"). The substitution is occurring as part of the implementation of the First Amended Plan of Reorganization Proposed by Debtor Big Rivers Electric Corporation Under Chapter 11 of the Bankruptcy Code as Modified and Restated June 9, 1997, as modified on June 1, 1998. See Appendix A—"REORGANIZATION" therein. Subject to the terms and conditions stated therein, the Bonds tendered for purchase and not remarketed will be purchased by the Liquidity Provider pursuant to the applicable Liquidity Facility. The Series 1983 Liquidity Facility will expire on June 1, 2013 and the Series 1985 Liquidity Facility will expire on October 1, 2015, unless earlier terminated or suspended upon the occurrence of certain events described herein, including certain events which would cause either of the Liquidity Facilities to be terminated without notice. See "SUMMARY OF THE LIQUIDITY FACILITIES" herein.

The Bonds will be subject to tender for purchase on demand of the owner thereof upon written notice to the Trustee. The Bonds also are subject to mandatory tender for purchase and optional, mandatory and extraordinary redemption as described herein upon the occurrence of certain circumstances described herein. See "DESCRIPTION OF THE SERIES 1983 BONDS" and "DESCRIPTION OF THE SERIES 1985 BONDS" herein.

The Bonds shall bear interest at the rate established in accordance with the provisions of the Indentures (as defined herein) commencing on the Effective Date. Interest will be payable on June 1 and December 1 with respect to the Series 1983 Bonds and on the first day of each month with respect to the Series 1985 Bonds as described herein by the Trustee. Principal of and premium, if any, due on the Bonds, whether at maturity, upon redemption or otherwise will be payable upon presentation and surrender at the principal corporate trust office of the Trustee. The purchase price due on the Bonds upon optional or mandatory tender for purchase will be payable upon presentation and surrender at the principal corporate trust office of the Trustee.

The Series 1983 Bonds are being remarketed as floating rate bonds. The Series 1985 Bonds are being remarketed as variable rate bonds bearing interest at a weekly interest rate. When remarketed, the Bonds will be registered in the name of Cede & Co., as nominee of The Depository Trust Company, New York, New York ("DTC"). Purchases of the Bonds will be made in book-entry form only, in the Authorized Denominations referred to herein, through brokers and dealers who are, or who act through, DTC participants. The Authorized Denominations for the Bonds will be denominations of $100,000 and any integral multiple thereof. Beneficial Owners of the Bonds will not be entitled to receive physical delivery of bond certificates so long as DTC or a successor securities depository acts as the securities depository with respect to the Bonds. So long as DTC or its nominee is the registered owner of the Bonds, reference herein to holders or registered owners of the Bonds will mean Cede & Co., as aforesaid, and payments of principal of and interest on the Bonds will be made directly to DTC by the Trustee. Disbursement of such payments to DTC participants is the responsibility of DTC and disbursement of such payments to the Beneficial Owners is the responsibility of DTC participants. See "DESCRIPTION OF THE BONDS—Book-Entry-Only System" herein.

Goldman, Sachs & Co.

July 9, 1998

INTRODUCTION

Big Rivers Electric Corporation ("Big Rivers") is an electric generation and transmission cooperative corporation that provides wholesale electric service to its four member electric distribution cooperatives (the "Members") and markets power to non-Member utilities and power marketers. Three Members founded Big Rivers in 1962 as a nonprofit rural electric cooperative to enable those Members to pool their resources and provide for the power and high-voltage transmission needs of their combined service territories. Big Rivers supplies power to its Members pursuant to wholesale power contracts which require the Members to buy and receive all of their power and energy requirements from Big Rivers.

The Members are local consumer-owned distribution cooperatives providing retail electric service on a not-for-profit basis. The Members consist of Green River Electric Corporation ("Green River"), Henderson Union Electric Cooperative Corp. ("Henderson Union"), Meade County Rural Electric Cooperative Corporation and Jackson Purchase Electric Cooperative Corporation. The customer base of the Members generally consists of residential, commercial and industrial consumers within specific geographic areas. Today, the Members provide electric power and energy to customers located in portions of 22 western Kentucky counties. As of December 31, 1997, the Members directly served approximately 91,500 member-customers (meters). Two industrial customers of the Members operating aluminum smelters accounted for approximately two-thirds of the energy purchased by the Members from Big Rivers in 1997.

On September 25, 1996, Big Rivers filed a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code ("Chapter 11"). Big Rivers since has operated as a debtor-in-possession under the supervision of the United States Bankruptcy Court for the Western District of Kentucky (the "Bankruptcy Court"). On June 9, 1997, the Bankruptcy Court confirmed a Plan of Reorganization proposed by Big Rivers (the "Plan of Reorganization"). On June 1, 1998 the Bankruptcy Court approved certain modifications to the Plan of Reorganization (as modified, the "Plan").

Upon the implementation of the Plan, Big Rivers and LG&E Energy Corp. ("LEC") and its affiliates will enter into certain transactions (the "LG&E Transaction") pursuant to which Big Rivers will lease its generating facilities to an affiliate of LEC and, as lessee of the generating facilities, such affiliate will own the output of the generating facilities in exchange for certain initial payments and fixed monthly payments over a term of approximately twenty-five years. During the LG&E Transaction, Big Rivers will purchase power from an affiliate of LEC, at fixed rates, in amounts up to certain contractually established maximum hourly and annual amounts allowed under a power purchase agreement with that affiliate of LEC and, where applicable, from other wholesale suppliers (under arrangements to be entered into in the future, if desired) in order to (i) satisfy Big Rivers' obligations to supply power to the Members under the wholesale power contracts with the Members (the "Wholesale Power Contracts"), as amended in connection with the Plan, and (ii) fulfill its obligations under certain other wholesale power sales agreements. No power will be provided by the affiliate of LEC to Big Rivers at fixed rates above these specified maximum hourly and annual amounts of power and Big Rivers will be responsible for arranging for deliveries of power in excess of such amounts from other wholesale suppliers. See "LG&E TRANSACTION—Power Purchase Arrangements Between Big Rivers and LG&E" herein. In addition, Big Rivers' purchases of power from an affiliate of LEC under the power purchase agreement will be subject to certain minimum purchase obligations.

In connection with the implementation of the Plan, Big Rivers and the Members will enter into amendments to the Wholesale Power Contracts. These amendments will create certain exceptions to the "all-requirements" nature of the Wholesale Power Contracts, including the sale of power by an affiliate of LEC to the Members to serve the energy requirements of the two aluminum smelters. See "GENERAL—Wholesale Power Contracts" and "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters" herein. The rates charged by Big Rivers to the Members under the Wholesale Power Contracts are subject to the approval of the Public Service Commission of the Commonwealth of Kentucky ("KPSC") because both Big Rivers and the Members are subject to its jurisdiction. See "GENERAL—Regulation of Big Rivers" herein.

Following the implementation of the Plan and the consummation of the LG&E Transaction, Big Rivers will continue to own and operate its transmission system and provide transmission services to the Members, affiliates of LEC and others. The Plan will become effective upon the satisfaction of certain conditions including the approval by the KPSC of the new rates to be charged by Big Rivers to the Members. It presently is expected that the Plan will become effective on July 15, 1998. The date the Plan becomes effective is hereinafter referred to as the "Effective Date."

REORGANIZATION

Several significant factors precipitated Big Rivers' bankruptcy filing under Chapter 11. These factors included (i) the impending default of Big Rivers on debt resulting from a debt restructuring in 1987, (ii) the inability to reach a consensual restructuring prior to the bankruptcy filing concerning Big Rivers' obligations to the banks providing letters of credit supporting Big Rivers' pollution control bonds, (iii) the need to address certain burdensome coal contracts and related litigation, (iv) the need to obtain certainty with respect to future cash flows, and (v) the need to address certain pending litigation.

Background and Purposes of the Reorganization

1987 Debt Restructuring

In 1985, Big Rivers began negotiating with its principal creditors to restructure its existing indebtedness in order to resolve Big Rivers' financial difficulties. Big Rivers had financed capital assets with funds provided under long-term loans, primarily from or guaranteed by the United States of America acting through the Rural Electrification Administration, the predecessor to the Rural Utilities Service ("RUS"), and through loans of the proceeds of pollution control bonds issued by the County of Ohio, Kentucky (the "Issuer"). The Issuer had loaned Big Rivers the proceeds of its Pollution Control Floating Rate Demand Bonds, Series 1983 (Big Rivers Electric Corporation Project) in the aggregate principal amount of $58,800,000 (the "Series 1983 Bonds"), and its Variable Rate Demand Pollution Control Refunding Bonds, Series 1985 (Big Rivers Electric Corporation Project) in the aggregate principal amount of $83,300,000 (the "Series 1985 Bonds" and, collectively with the Series 1983 Bonds, the "Bonds"). The Bonds were supported by irrevocable letters of credit (the "Letters of Credit") issued by Irving Trust Company, currently known as The Bank of New York (the "Series 1983 Bonds Letter of Credit Bank"), and Manufacturers Hanover Trust Company, predecessor to The Chase Manhattan Bank (the "Series 1985 Bonds Letter of Credit Bank" and, collectively with the Series 1983 Bonds Letter of Credit Bank, the "Banks").

Big Rivers reached an agreement with its principal creditors on the restructuring of its indebtedness in March of 1988 and entered into a debt restructuring agreement, dated as of August 31, 1987, among Big Rivers, RUS and the predecessors to the Banks (the "1987 Restructuring Agreement"). The 1987 Restructuring Agreement effectively consolidated debt owed directly to RUS with debt previously guaranteed by RUS. Under the 1987 Restructuring Agreement, Big Rivers became obligated directly to RUS on the consolidated debt and executed a note in favor of RUS evidencing such debt in the principal amount of $1,192,309,142.02 (the "1987 RUS Note"). The 1987 RUS Note bore interest at an effective rate of 8.0% per annum. The 1987 Restructuring Agreement provided for a reverse amortization schedule for amounts due under the 1987 RUS Note.

The 1987 Restructuring Agreement subsequently was amended in connection with the execution of the Settlement Agreement, dated as of January 1, 1990 (the "1990 Settlement Agreement"), among Big Rivers and two aluminum smelters which purchased power from the Members, NSA, Inc. ("NSA"), a subsidiary of Southwire Company ("Southwire"), and Alcan Aluminum Corporation ("Alcan" and, collectively with Southwire, the "Smelters"). The 1987 Restructuring Agreement required the Smelters to pay a variable rate for energy based on the market price of aluminum. The 1990 Settlement Agreement, however, fixed the revenue to be recognized by Big Rivers on the sale of such energy to the Members serving the Smelters.

Reasons for Failure of 1987 Debt Restructuring

The success of the 1987 Restructuring Agreement was premised upon the rates approved by the KPSC in an order issued on August 10, 1987 (the "1987 Order"). The rates adopted in the 1987 Order anticipated that Big Rivers would be able to repay its debt following the restructuring with revenues from (i) the new rates contained in the 1987 Order and (ii) projected off-system sales of power to third parties.

Because Big Rivers sold less power to third parties from 1987 through 1995 than anticipated, Big Rivers was unable to achieve projected sales and revenue targets for off-system sales. Faced with impending default under the 1987 Restructuring Agreement, Big Rivers' board of directors (the "Board") commenced a process to resolve the impending default. In 1994, Big Rivers created a subcommittee of the Board to establish and manage a process for addressing inquiries Big Rivers had received from other electric utilities regarding the purchase or lease of Big Rivers' assets and resolving Big Rivers' financial difficulties. In 1995, Big Rivers selected a turnaround consultant to assist this subcommittee and the Board in the management of this process.

On January 30, 1996, Big Rivers executed a letter of intent with PacifiCorp Holdings, Inc. ("PacifiCorp"). The letter of intent set forth the parties' intent to enter into a transaction in which a newly formed subsidiary of PacifiCorp would lease Big Rivers' generating facilities for a period of approximately twenty-five years. During this period, this subsidiary would sell back to Big Rivers a substantial portion of Big Rivers' wholesale power requirements.

Big Rivers hoped to achieve its restructuring consensually and without the necessity of filing for bankruptcy under Chapter 11. Big Rivers engaged in negotiations over a period of many months with RUS, the Banks, the Members, the Smelters and PacifiCorp in an attempt to forge a comprehensive agreement based on the proposed transaction with PacifiCorp. A comprehensive agreement was not reached by all parties and, on September 25, 1996, Big Rivers filed a petition for bankruptcy under Chapter 11 with the Bankruptcy Court.

Outstanding Debt Prior to Reorganization

At the time of Big Rivers' bankruptcy filing, Big Rivers' principal creditors consisted of RUS and the Banks. On September 25, 1996, the aggregate amount owed by Big Rivers to RUS under the 1987 RUS Note was $1,101,165,116. On such date, the total aggregate principal amount of the Series 1983 Bonds and the Series 1985 Bonds ($58,800,000 and $83,300,000, respectively) was outstanding. Payment on the Bonds was and, and until the Effective Date, is secured by the Letters of Credit. Big Rivers is obligated, however, to reimburse the Banks for any amounts paid by them under their respective Letters of Credit pursuant to reimbursement agreements with the Banks.

The Plan and Effects of Reorganization

Description of the Plan

Big Rivers filed a plan of reorganization based on the transaction with PacifiCorp with the Bankruptcy Court on January 22, 1997. On February 21, 1997, the Bankruptcy Court ordered an auction process to assure that the proposed PacifiCorp transaction produced the maximum value for creditors. On March 19, 1997, the Bankruptcy Court declared LEC to be the successful bidder of the auction. Thereafter, Big Rivers filed the Plan of Reorganization incorporating the LG&E Transaction with the Bankruptcy Court. In general, the LG&E Transaction contemplates the lease of the generating facilities of Big Rivers to affiliates of LEC in exchange for certain initial payments and fixed monthly payments over a term of approximately twenty-five years.

The Plan of Reorganization was confirmed by the Bankruptcy Court on June 9, 1997. Subsequently, the Bankruptcy Court on June 1, 1998 entered an order approving modifications to the Plan of Reorganization and to the proposed transaction with LEC and its affiliates. Following the satisfaction of certain conditions, the Plan will become effective. The LG&E Transaction, described below, will be implemented on the Effective Date.

In general, the implementation of the Plan will result in (i) a cash payment to RUS on the Effective Date and the issuance of two promissory notes to the RUS, one to be amortized over approximately twenty-five years and one to be paid at the end of a term of approximately 25 years (in each case, unless sooner accelerated under the terms governing such notes), (ii) the release of the Banks from their obligations under the Letters of Credit, (iii) the payment by the Banks of certain sums to Big Rivers, (iv) the remarketing of the Bonds with new credit enhancement facilities to be substituted for the Letters of Credit, (v) payment in full or agreed payments of all General Unsecured Claims (as defined in the Plan) and (vi) the continuation of Big Rivers as a transmission service provider and wholesale power provider with continued ownership of its generating facilities (but not their output) during the term of the LG&E Transaction.

Debt of Big Rivers Following Effective Date

Following the Effective Date, Big Rivers' long-term debt primarily will consist of (i) indebtedness to RUS, (ii) indebtedness relating to the Bonds, (iii) indebtedness under a revolving line of credit in an amount not to exceed $15 million, and (iv) indebtedness to an affiliate of LEC.

On the Effective Date, Big Rivers will issue to RUS a secured note in the aggregate principal amount of $1,101,165,000 less the cash payment due to RUS on the Effective Date and currently estimated to be approximately $80,923,000 (the "New RUS Note"). (If the Effective Date occurs after July 1, 1998, the cash payment due to the RUS will decrease by $66,666.66 per day provided that the aggregate decrease will not exceed $2 million. The cash payment to RUS is also subject to certain additional adjustments that depend on the net amount of cash available to Big Rivers on the Effective Date.) The New RUS Note will mature approximately twenty-five years after the Effective Date. The New RUS Note is structured so that it will amortize fully over its term. The New RUS Note will bear interest at the rate of 5.75% per annum and will require quarterly payments of principal and interest. (The actual interest rate will be determined on the Effective Date and may vary slightly from 5.75% depending on the actual amount of the cash payment to RUS on the Effective Date.) In addition, Big Rivers will issue a second secured note to RUS on the Effective Date in the aggregate principal amount of $265,000,000 (the "ARVP Note"). The ARVP Note will not bear interest and will not require any payments prior to its maturity date approximately twenty-five years after the Effective Date. The Plan will require, however, that Big Rivers make payments equal to one-third of certain arbitrage profits from the sale of power, if any, and to use certain net amounts, if any, recovered by Big Rivers in connection with litigation relating to fraud in connection with certain long-term coal contracts entered into by Big Rivers less certain costs associated with obtaining such recovered amounts to repay principal of the ARVP Note.

In addition to the New RUS Note and the ARVP Note, Big Rivers will have continuing obligations with respect to the payment of the principal of and premium, if any, and interest on the Bonds. Big Rivers' obligations with respect to the Bonds will be unaffected in the reorganization. However, the Letters of Credit issued by the Banks will be replaced on the Effective Date by two liquidity facilities to be issued by Credit Suisse First Boston, New York, New York (the "Liquidity Provider") and municipal bond insurance policies to be issued by Ambac Assurance Corporation ("Ambac"). On the Effective Date, Ambac will issue two financial guarantee insurance policies which will guarantee the full and timely payment of the principal of and interest on the Bonds. In addition, Ambac will issue three surety policies in order to insure the full and timely payment of certain fees owed to the Liquidity Provider. Under two separate reimbursement agreements (the "Reimbursement Agreements"), Big Rivers will agree to reimburse Ambac for any payments under the municipal bond insurance policies or the surety policies. Big Rivers' reimbursement obligation to Ambac also will be evidenced by five notes: a note relating to Series 1983 Bonds in an aggregate principal equal to $58,800,000; a note relating to the Series 1985 Bonds in an amount equal to $83,300,000; a note relating to the surety policy for the Series 1983 Bonds; a note relating to the surety policy for the Series 1985 Bonds; and a note relating to the surety policy for certain charges and fee amounts relating to the Series 1985 Bonds.

National Rural Utilities Cooperative Finance Corporation ("CFC") has agreed to provide Big Rivers on the Effective Date with a secured, revolving line of credit, having a five-year term, in an aggregate principal amount not to exceed $15 million (the "Line of Credit") subject to certain conditions. The Line of Credit will be used for short-term cash flow needs of Big Rivers. CFC will require that no amounts be outstanding under the Line of Credit for a period of five business days at least once each year. Any advances under the Line of Credit will bear interest at CFC's standard line of credit rate. Big Rivers will make payments of interest on any amounts outstanding under the Line of Credit on a quarterly basis.

On the Effective Date, Big Rivers will deliver a promissory note to LG&E Energy Marketing Inc., the power marketing affiliate and wholly owned subsidiary of LEC ("LEM"), in exchange for certain agreements entered into by affiliates of LEC on the Effective Date (the "Settlement Note"). The Settlement Note will require Big Rivers to pay to LEM approximately $19.7 million, plus interest, over a 25-year period (regardless of whether or not the LG&E Transaction is terminated before the end of 25 years). See "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters" and "LG&E TRANSACTION—General."

New RUS Mortgage

On the Effective Date, Big Rivers will execute and deliver the Restated Mortgage and Security Agreement (the "New RUS Mortgage") in favor of RUS, Ambac and CFC, as mortgagees. The New RUS Mortgage will grant a mortgage lien on virtually all of the assets and properties of Big Rivers to secure Big Rivers' obligations to Ambac and CFC as described above and, on a subordinate basis, Big Rivers' obligations to RUS under the New RUS Note and the ARVP Note. The Bonds will not be secured under the New RUS Mortgage. In connection with the LG&E Transaction, however, Big Rivers will grant affiliates of LEC two mortgages on certain property of Big Rivers the first of which will be subordinate to Ambac and CFC as specified in a Subordination, Nondisturbance, Attornment and Intercreditor Agreement, dated as of the Effective Date (the "Nondisturbance Agreement"), among Big Rivers, certain affiliates of LEC, RUS, Ambac and CFC (and pari passu with RUS as specified in the Nondisturbance Agreement) and the second of which will be subordinate to Ambac, CFC and RUS. RUS, Ambac, CFC and certain affiliates of LEC will execute the Nondisturbance Agreement which will grant affiliates of LEC assurances that RUS, Ambac and CFC will not disturb agreements relating to the LG&E Transaction by reason of a default by Big Rivers under the New RUS Mortgage and which will address issues relating to the priority of the liens of Ambac, CFC, RUS and affiliates of LEC. See "Subordinated Mortgage," "LEM Mortgage" and "Nondisturbance Agreement" in Appendix B.

Status of Members Following Effective Date

The articles of incorporation and bylaws of Big Rivers will continue to govern the Members' rights with respect to the governance of Big Rivers and the Members' residual interest in Big Rivers following the Effective Date. However, the Plan, if implemented, will terminate any existing claims the Members have against Big Rivers prior to the Effective Date including any claims related to contractual liabilities, capital contributions, overpayments, causes of action, rights or entitlements to refunds, adjustments respecting rates, or claims for patronage capital.

In order for the Members to sell energy to the Smelters according to the terms agreed upon in the Plan, Big Rivers and the two Members which provide retail service to the Smelters will amend their Wholesale Power Contracts. See "GENERAL—Wholesale Power Contracts" herein. The amendments will permit the two Members which provide retail service to the Smelters to purchase power from an affiliate of LEC for all of the Smelters' power requirements through December 31, 2000, and thereafter to purchase certain quantities of wholesale power to be resold to the Smelters from an affiliate of LEC and to purchase certain additional quantities of such power from LEM or other wholesale power suppliers. See "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters" herein.

Rate Adjustments in Connection with the Reorganization

On June 30, 1997, Big Rivers filed a joint application with affiliates of LEC with the KPSC (the "Application") seeking approval of an interim adjustment in Big Rivers' existing rates and tariffs for wholesale electric service during the period from September 1, 1997 through the earlier of the Effective Date or August 31, 1998 (the "Interim Rates"). The Interim Rates as proposed were the rates that otherwise would have been applicable during the first year of the LG&E Transaction. This interim rate adjustment was obtained as part of Big Rivers' agreement with the Members and the Smelters to implement on an interim basis the rates and tariffs contemplated by the Plan of Reorganization as soon as possible. In the Application, Big Rivers also sought approval of the permanent implementation of the rates and tariffs contemplated by the Plan of Reorganization for wholesale electric service to the Members (the "Transaction Rates" or "Transaction Tariff," as applicable). Big Rivers requested that the Transaction Rates become effective on the Effective Date.

The Interim Rates became effective on September 2, 1997, and will remain in effect through the consummation of the LG&E Transaction or further order by the KPSC. The day after the consummation of the LG&E Transaction, the Transaction Rates will become effective. The modifications made by the KPSC to the rate structure were incorporated into the Plan and accepted by those parties whose consent was required thereunder and were approved by the Bankruptcy Court on June 1, 1998.

The order of the KPSC which approved the Transaction Rates is subject to final resolution of any petitions for rehearing and to any appeals. Every order entered by the KPSC continues in force until the expiration of the time, if any, stated in the order, or until revoked or modified by the KPSC unless the order is suspended, or vacated in whole or in part, by order of decree of a court of competent jurisdiction. The times for seeking rehearing and for appeal of the order approving the Transaction Rates have expired, except to the extent that rehearing granted by the KPSC in that case on June 11, 1998, has tolled the time for appeal. See also "LG&E TRANSACTION—Required Regulatory Approvals."

The Transaction Rates distinguish between sales to Members on behalf of certain large industrial customers (including the Smelters), and all other customers of the Members. The Transaction Rates will result in a decrease in Big Rivers rates for wholesale electric service to the Members from the rates in effect prior to the bankruptcy filing. This decrease will have a favorable impact on the competitiveness of Big Rivers' rates. See also "MEMBERS—Competition and Rate Comparison" herein.

Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters

The Smelters currently purchase approximately two-thirds of the energy sold by Big Rivers' Members. As part of the Plan, Big Rivers, Green River, Henderson Union and the Smelters will restructure the agreements among them pursuant to which the Smelters purchased power from Green River and Henderson Union (currently provided by Big Rivers) and will resolve all of their existing disputes. The Plan terminates Big Rivers' contractual obligation to sell, and Green River's and Henderson Union's contractual obligation to purchase from Big Rivers, the wholesale power to be resold to the Smelters. Instead, Big Rivers and LEC have agreed that LEM will become the supplier of such wholesale power to Green River and Henderson Union on the day following the Effective Date for all power sold by the Members to the Smelters through December 31, 2000, and for certain quantities of such power thereafter. Under the Plan, LEM will pay Big Rivers certain amounts equal to the adjusted margins on power that was projected to be available to the Smelters, regardless of the actual Smelter demand (the "Monthly Margin Payment").

Electric Service Agreements and LEM Wholesale Power Agreements

As contemplated by the Plan, Green River and Henderson Union each will enter into an electric service agreement, dated the Effective Date, with Southwire and Alcan, respectively, relating to the future supply of energy to the Smelters (collectively, the "Electric Service Agreements"). Also on or before the Effective Date, Green River and Henderson Union each will enter a wholesale power supply agreement, dated the Effective Date, with LEM relating to the future supply of most of the energy to be consumed by the Smelters under the Electric Service Agreements (collectively, the "LEM Wholesale Power Agreements"). The Electric Service Agreements and the LEM Wholesale Power Agreements terminate with respect to Green River's sales to Southwire on December 31, 2010 and with respect to Henderson Union's sales to Alcan on December 31, 2011.

Rates applicable to the Smelters will be based on three categories, or tiers, of demand for energy by the Smelters. Other than provisions for a Member's distribution adder, the Electric Service Agreements and the LEM Wholesale Power Agreements contain identical terms relating to the rates and volumes of capacity and energy to be supplied pursuant to Tier 1 and Tier 2, and through 2000, Tier 3. The Electric Service Agreements and the LEM Wholesale Power Agreements provide for certain "take-or-pay" obligations of the Smelters with respect to specified amounts of power ("Tier 1 Demand"). Unlike Tier 1 Demand, the Smelters will not be subject to minimum purchase obligations to the Members and LEM with respect to certain specified amounts of power in excess of Tier 1 Demand and will not be required to pay for any such unused "Tier 2 Demand." However, an LEC affiliate still will be required to pay Big Rivers the full amount of the Monthly Margin Payment regardless of whether the Smelters purchase their full Tier 2 Demand. The "Tier 3 Demand" of a Smelter will be its power purchases in excess of its Tier 1 Demand and Tier 2 Demand. Beginning January 1, 2001, the rate paid by the Smelters for Tier 3 Demand will reflect the costs of the wholesale suppliers of energy selected by Green River and Henderson Union. See "GENERAL—Wholesale Power Contracts" herein.

Transmission Rates

With respect to Tier 1 Demand and Tier 2 Demand, LEM will purchase transmission service from Big Rivers pursuant to Big Rivers' Open Access Transmission Tariff (the "Tariff") filed with the Federal Energy Regulatory Commission ("FERC") for delivery of energy consumed by the Smelters. Although LEM will reserve and pay for this transmission in accordance with the rates, terms and conditions of the Tariff using Big Rivers' Open Access Same-time Information System ("OASIS"), these payments for Tier 1 and Tier 2 transmission services will be included as part of the established Monthly Margin Payment. Big Rivers will not charge LEM separately for such transmission so long as it or the RUS continues to receive the Monthly Margin Payments. Green River and Henderson Union, either directly or indirectly through LEM, will contract for certain additional transmission service required to deliver Tier 3 Demand. Commencing on the Effective Date, Green River and Henderson Union will specify the type and amount of transmission service they will use for delivery of Tier 3 Demand. Big Rivers then will charge Green River and Henderson Union for the transmission service reserved by them for Tier 3 Demand. Consistent with FERC requirements, Big Rivers will retain a native load transmission planning obligation with respect to Smelter load growth through December 31, 2001.

Resolution of Pending Proceedings

Prior to the time of Big Rivers' bankruptcy filing under Chapter 11, several disputes arose between Big Rivers and the Smelters relating to the terms of the provision of electric service by Green River and Henderson Union to the Smelters. At the time of Big Rivers' bankruptcy filing, the Smelters were asserting claims affecting Big Rivers in several separate litigation and regulatory proceedings. In addition, Big Rivers was pursuing claims affecting the Smelters in other litigation and regulatory proceedings at such time.

Big Rivers and the Smelters have agreed to enter into a standstill agreement with respect to certain legal proceedings until other conditions precedent to the effectiveness of the Plan have been satisfied or until either party files a notice to recommence such proceedings. Big Rivers and the Smelters have agreed to dismiss all claims against each other in those legal proceedings upon the effectiveness of the Plan. Big Rivers and the Smelters settled a proceeding concerning an environmental surcharge contained in the Big Rivers' tariff prior to the filing for bankruptcy reorganization without regard to whether the Plan becomes effective. The Smelters are the principal parties in several cases either pending before the KPSC or on appeal from orders of the KPSC regarding the application by Big Rivers of a fuel adjustment clause in its tariff prior to filing for bankruptcy reorganization. In those cases, the Smelters have sought a refund of portions of the amounts collected by Big Rivers under the fuel adjustment clause in such tariff. The Plan provides that when the Plan becomes effective, the claims involved in these cases will be deemed settled, discharged and released, these cases will be dismissed with prejudice and the Smelters will not seek further relief in the fuel adjustment clause cases, will not claim refunds with respect thereto, and will return any refunds received after May 31, 1998, related to such proceedings and any subsequent fuel adjustment clause case. The Transaction Rates do not include a fuel adjustment clause.

The Plan provides that on the Effective Date the Banks, the Smelters and the Members will execute and deliver mutual releases with respect to any and all claims and causes of action existing between or among any of them prior to the Effective Date. The Plan further provides that, on the Effective Date, the Smelters, Kentucky Industrial Utility Customers, Inc. ("KIUC"), Commonwealth Aluminum Company, the Attorney General for the Commonwealth of Kentucky and their successors will settle and release, and shall be deemed to have settled and released, all claims and causes of action against Big Rivers and the Members and against any of their current and former directors, officers, employees, agents or attorneys (other than certain claims against a former executive of Big Rivers and an accounting firm) based on any conduct, transaction or occurrence on or prior to the Effective Date. The Plan also contemplates that the Smelters and related parties (including Southwire, KIUC, Green River and Henderson Union) will take all reasonable actions following the Effective Date to dismiss with prejudice those claims asserted by Big Rivers against the Smelters, Southwire and KIUC in the actions referenced in the Plan and those claims asserted by NSA, Southwire or Alcan against or on behalf of Big Rivers, Green River or Henderson Union in the actions referenced in the Plan.

The Plan contemplates that Big Rivers and the Smelters will agree to withdraw existing complaints against each other before the KPSC following the Effective Date. With respect to a restitution case pending before the KPSC, RUS and the Members, for the benefit of the ratepayers, will divide equally amounts received by Big Rivers as restitution or payable on its fidelity policy or recovered as damages through the date the KPSC implements the Interim Rates. The parties have agreed to evaluate claims against third parties in the coal cases and cooperate in the resolution of these and other claims. Also, they will agree to divide equally all post-Effective Date fraud recoveries between RUS and the Members after payment of Big Rivers' and the Smelters' legal costs in pursuing those claims. Amounts to be refunded to the Members will be passed through to the Smelters and other retail customers under a methodology approved by the KPSC based, at least in part, on historic energy usage by the Smelters and other retail customers consistent with the time period in which the revenues for fuel purchases under the related coal contracts were collected.

LG&E TRANSACTION

General

The LG&E Transaction will result in the lease of Big Rivers' generating plants (the "Facilities") in exchange for certain fixed payments. During the term of the LG&E Transaction, Big Rivers will lease the Facilities to Western Kentucky Energy Corp., a wholly owned subsidiary of LEC ("WKEC"), pursuant to a Lease and Operating Agreement, dated the Effective Date (the "Lease"). Pursuant to the Lease, WKEC will own the output of the Facilities. See "Operation of the Facilities" herein. In order to fulfill its obligation to supply power to the Members and others following the Effective Date, Big Rivers will purchase power from LEM pursuant to a Power Purchase Agreement, dated the Effective Date, between Big Rivers and LEM (the "Power Purchase Agreement"). See "Power Purchase Arrangements Between Big Rivers and LEM" herein. As part of the LG&E Transaction, WKEC also will purchase certain personal property, inventory and intangible assets necessary for the operation of the Facilities from Big Rivers pursuant to a New Participation Agreement, dated April 6, 1998 (the "Participation Agreement"). See "Payments During LG&E Transaction" herein.

The LG&E Transaction contemplates certain arrangements with respect to the operation of the Henderson Municipal Power & Light Station Two Generating Facility (the "Station Two Facility"). The City of Henderson, Kentucky ("Henderson") owns the Station Two Facility but Big Rivers currently operates the facility on behalf of the City of Henderson Utility Commission, doing business as Henderson

Municipal Power & Light ("HMP&L"). Big Rivers currently purchases a substantial quantity of the output of the Station Two Facility from HMP&L. On the Effective Date, WKE Station Two Inc. (the "Station Two Subsidiary" and, collectively with LEC, LEM and WKEC, the "LG&E Entities") will assume certain of Big Rivers' obligations to Henderson with respect to the Station Two Facility pursuant to the underlying contracts between Big Rivers and Henderson. The Station Two Subsidiary will, in turn, be entitled to the rights of Big Rivers in the capacity and energy of the Station Two Facility not taken by Henderson.

Station Two Facility

The Station Two Subsidiary will assume certain obligations of Big Rivers to Henderson under certain contracts between Big Rivers and Henderson pursuant to an Agreement and Amendments to Agreements, dated the Effective Date, among Henderson, City of Henderson Utility Commission, Big Rivers, the Station Two Subsidiary, LEM and WKEC (the "Station Two Agreement"). Pursuant to the Station Two Agreement, the Station Two Subsidiary will acquire directly from Henderson all the output from the Station Two Facility surplus to the output reserved by Henderson for its needs. The Station Two Subsidiary will purchase certain personal property, inventory and intangible assets of Big Rivers necessary for the operation of the Station Two Facility pursuant to the Station Two Agreement.

The terms of the tax-exempt bonds used to finance the Station Two Facility require power from the Station Two Facility to be used in a two-county area served by the Members and HMP&L until such bonds are retired. Such bonds mature in 2003 if not retired earlier. During the term of the LG&E Transaction, Big Rivers will assign to the Station Two Subsidiary certain of its obligations under agreements with HMP&L for the operation of the Station Two Facility (with the exception of obligations relating to transmission services and jointly owned facilities not related to generation, which will be retained by Big Rivers) and its rights under those agreements with respect to the purchase of the output of the Station Two Facility. Neither LEM nor the Station Two Subsidiary will sell output of the Station Two Facility outside the two-county area served by the Members and HMP&L until the tax-exempt bonds used to finance the Station Two Facility are retired.

On or prior to the Effective Date, Big Rivers, HMP&L and the LG&E Entities will execute an agreement providing for an appropriate and reasonable allocation to the Station Two Facility of each of their anticipated general and administrative expenses associated with their respective performance obligations with respect to the Station Two Facility. In addition, on the Effective Date, Big Rivers and Henderson will amend the Systems Reserve Agreement, dated as of January 1, 1974, which requires each party to provide certain operating reserves to the other and to maintain certain reserve requirements for their respective electric systems while they remain interconnected. Pursuant to the amended agreement, the LG&E Entities will agree to undertake to provide Henderson with certain of the operating reserves required for its electric system.

Payments During LG&E Transaction

On the Effective Date, Big Rivers will receive an initial payment of approximately $55,856,600 (the "Initial Fixed Payment") and a closing enhancement payment of $12.1 million. In addition, WKEC and the Station Two Subsidiary will purchase on the Effective Date certain inventory and personal property of Big Rivers used in the operation of the Facilities and the Station Two Facility at an agreed-upon value currently estimated by Big Rivers to be approximately $37.5 million. The inventory of Big Rivers sold to WKEC will consist of fuel and scrubber reagents, spare parts, and other materials and supplies held for use in connection with the operation of the Facilities and the Station Two Facility and all of Big Rivers' rights and interest in SO_2 allowances with vintage years prior to the calendar year of the Effective Date (the "Inventory"). The personal property sold by Big Rivers to WKEC will consist of certain property currently used or held exclusively for use in connection with the operation of the Facilities and the Station Two Facility (the "Personal Property"). On the Effective Date, Big Rivers also will assign to WKEC certain intangible assets, including its rights under real property leases, equipment leases, permits, intellectual property, and contracts used or held exclusively for use in connection with the operation of the Facilities and Station Two Facility (the "Intangible Assets"), and WKEC will assume all of Big Rivers' obligations under the Intangible Assets which first arise or accrue on or after the Effective Date.

On the Effective Date, Big Rivers will execute the Settlement Note in favor of LEM. The Settlement Note will require Big Rivers to pay to LEM approximately $19.7 million, with interest, over a 25-year period (regardless of whether the LG&E Transaction is terminated before the end of 25 years). This payment is consideration for LEM's assumption of the risk of unforeseen costs with respect to power to be supplied to or for the use of the Smelters and other changes made to the LG&E Transaction in the period between the confirmation of the Plan of Reorganization and the approval on June 1, 1998 of the modification to the Plan of Reorganization, including increased financial responsibility for financing capital improvements. See "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters."

Pursuant to the terms of the Interim Wholesale Marketing Assistance Agreement, dated June 18, 1997, between Big Rivers and LEM, as amended (the "Interim Marketing Agreement"), Big Rivers will pay to LEM a non-refundable marketing payment (the "Marketing Payment") on the Effective Date, in an amount determined as follows: (a) if the Effective Date occurs on or before July 1, 1998, the Marketing Payment will be $5 million; (b) if the Effective Date occurs following July 1, 1998 but prior to August 1, 1998, the Marketing Payment will be $5 million plus the product of (i) $2 million and (ii) a fraction, the numerator of which is the total number of days following July 1, 1998 through and including the Effective Date and the denominator of which is 30; and (c) if the Effective Date occurs following July 31, 1998, the Marketing Payment will be $7 million. If the Marketing Payment exceeds $5 million, LEM will enter into a demand note in favor of RUS. This note will require LEM to pay RUS such amount received in excess of $5 million on behalf of Big Rivers if Big Rivers ever defaults to RUS up to the amount of such default and subject to Big Rivers' obligation to repay LEM after repayment of all of its debt to the RUS, Ambac and certain other creditors including all amounts due under the Bonds.

Beginning on the second anniversary of the Effective Date, WKEC will pay Big Rivers annual lease payments of approximately $31 million on a monthly basis. These monthly payments are subject to adjustment for certain environmental costs and changes in the amount of power purchased by Big Rivers from LEM over the LG&E Transaction Term. Finally, the Station Two Agreement subjects the monthly fixed payments to adjustment if the output from the Station Two Facility in excess of Henderson's needs generally is not available to LEM or the Station Two Subsidiary for purchase based on certain actions of Big Rivers.

During the first two years following the Effective Date, LEM will make monthly advances to Big Rivers totaling $50 million. During the next three years, Big Rivers will repay, solely by an offset mechanism, a total of $60 million, by paying $15 million during the third year of the LG&E Transaction Term, $20 million during the fourth year, and $25 million during the fifth year.

Each month from the Effective Date through January, 2012, WKEC also will pay to Big Rivers the Monthly Margin Payments pursuant to the Lease. These payments are intended to compensate Big Rivers for the loss of profits it anticipated receiving from the sale of power to Green River and

Henderson Union for resale to the Smelters. See "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters."

Big Rivers and the LG&E Entities have agreed to certain incremental payments by Big Rivers to the LG&E Entities primarily related to incremental revenue Big Rivers may receive based on the future volume of Tier 3 transmission reserved on Big Rivers' transmission system by Henderson Union and Green River for Tier 3 power consumed at retail by Alcan and Southwire. With respect to future Tier 3 Demand of Alcan, Big Rivers will, commencing on the second occurrence of a 25th day of the month after the Effective Date, pay LEM through January 25, 2004, an amount equal to 34.3% of the revenues received by Big Rivers from Henderson Union or its wholesale supplier from transmitting Tier 3 Demand to Alcan during the preceding month. No such payments will be made by Big Rivers to LEM unless incremental revenues are received by Big Rivers from Henderson Union or its wholesale power supplier for transmitting Tier 3 Demand sold to Alcan. With respect to Southwire, so long as Green River agrees to a ten-year take-or-pay minimum commitment of $1 million per year for transmission of Tier 3 Demand for Southwire, commencing January 1, 2001 and terminating December 31, 2010, Big Rivers will pay to LEM $400,000 plus the lesser of $258,320 or the amount in excess of $1 million (subject to certain adjustments in the event Big Rivers' rates for transmission are below $0.98 per kW month for firm point-to-point transmission service) received by Big Rivers for service during such period from Green River or its wholesale power supplier for transmitting Tier 3 Demand sold to Southwire.

During the LG&E Transaction Term, Big Rivers will be entitled to certain credits against amounts it owes to LEM under the Power Purchase Agreement. Each month during the first fifty-five months of the LG&E Transaction Term, Big Rivers will receive a credit of $89,000. For the year 2011, Big Rivers will receive a credit of $2,610,557. For the year 2012 and each subsequent year during the LG&E Transaction Term, Big Rivers will receive a credit of $4,110,750.

Big Rivers and WKEC will share certain costs relating to the Facilities during the LG&E Transaction Term, including property taxes, capital expenditures which are necessary to maintain the current capacity of the Facilities or to comply with the requirements of law, and certain increased operation and maintenance costs attributable to a change in environmental law after the Effective Date. The portion of each of these costs to be borne by each party will change during the LG&E Transaction Term to reflect changes in the maximum and minimum annual and hourly power purchase amounts under the Power Purchase Agreement in 2011, again in 2012 and if Big Rivers elects to reduce the maximum and minimum annual and hourly power purchase amounts.

Operation of the Facilities

On the Effective Date, WKEC will lease the Facilities from Big Rivers pursuant to the Lease. Similarly, the Station Two Subsidiary will assume certain obligations of Big Rivers relating to the operation of the Station Two Facility. As lessee of the Facilities, WKEC will have title to the power generated by the Facilities. The Station Two Subsidiary, as Big Rivers' assignee, will purchase a portion of the power generated by the Station Two Facility from Henderson. WKEC (with respect to the Facilities) and the Station Two Subsidiary (with respect to the Station Two) will be responsible generally for the operation, maintenance, and management of the Facilities and the Station Two Facility, the oversight of the design, construction and placing into service of all capital assets, and the development of an annual capital budget and annual operations and maintenance ("O&M") budget for the Facilities and the Station Two Facility. See "Lease" and "Station Two Agreement" in Appendix B.

WKEC and the Station Two Subsidiary, as applicable, have agreed to indemnify Big Rivers for any and all claims, losses, damages, costs and expenses incurred by Big Rivers as a result of WKEC's, the Station Two Subsidiary's or any of their affiliates', operation or use of the Facilities and the Station Two Facility, except for losses caused by certain actions of Big Rivers or certain environmental liabilities for which Big Rivers has agreed to assume responsibility. See "Participation Agreement" and "Station Two Agreement" in Appendix B.

WKEC or the Station Two Subsidiary (as appropriate) will assume and agree to discharge Big Rivers' performance obligations arising after the Effective Date with respect to the Intangible Assets. WKEC or the Station Two Subsidiary (as appropriate) will be responsible for maintaining and replacing any and all Intangible Assets needed to operate the Facilities and the Station Two Subsidiary in a manner consistent with prudent utility practice. WKEC will be responsible for communicating with Big Rivers regarding the status of the Intangible Assets that are used in connection with the Facility. Such communications will occur through the Operating Committee formed by Big Rivers and WKEC, discussed below. See "Operations of Big Rivers During the Term of the LG&E Transaction" herein. Similarly, the Station Two Subsidiary will have the responsibility of informing the Operating Committee formed of representatives of the Station Two Subsidiary and Big Rivers of material changes to the Intangible Assets relating to the Station Two Facility. To the extent a permit or other regulatory approval needed to operate the Facilities or the Station Two Facility cannot be assigned to WKEC or the Station Two Subsidiary on the Effective Date, Big Rivers will make such permit available to WKEC or the Station Two Subsidiary, to the extent possible, at no additional charge.

LEM will provide generation-based ancillary services needed to support the operation of Big Rivers' transmission facilities using its rights to plant output purchased from WKEC and the Station Two Subsidiary. Big Rivers and WKEC will share responsibility for property taxes, capital expenditures and certain O&M expenditures related to the Facilities according to agreed upon cost allocations. See "Power Purchase Arrangements Between Big Rivers and LG&E" herein and "Lease" and "Participation Agreement" in Appendix B. Similar provisions will apply with respect to the Station Two Facility pursuant to the Station Two Agreement.

Power Purchase Arrangements Between Big Rivers and LEM

Following the Effective Date, WKEC, as lessee of the Facilities, will own all of the power generated by the Facilities and may sell such output to LEM. Similarly, the Station Two Subsidiary will own Big Rivers' contractual entitlement to the output of the Station Two Facility and may sell such output to LEM. Pursuant to the Power Purchase Agreement, LEM will sell certain quantities of power to Big Rivers, subject to certain hourly and annual minimums and maximums and other contract requirements. This power will be in addition to power Big Rivers acquires from the Southeastern Power Administration ("SEPA"). LEM will commit to make this power available for sale at prices established in the Power Purchase Agreement.

Sources of Power

The Power Purchase Agreement will not link the power LEM sells to Big Rivers to the power produced by the Facilities and the Station Two Facility. The Power Purchase Agreement will not obligate LEM to supply power to Big Rivers from any particular source but it will require delivery of certain amounts of power on Big Rivers' transmission system at points of delivery specified at the time of scheduling. As a result, the obligation of LEM to supply power to Big Rivers will be independent of the continued production of power from the Facilities and the Station Two Facility, provided Big Rivers does not default on any of its obligations under the agreements relating to the LG&E Transaction. Accordingly, the Power Purchase Agreement requires LEM to continue to deliver power to Big Rivers, subject to certain uncontrollable forces, even if the production of power at the Facilities or the Station

Two Facility is inhibited as long as such occurrence is not caused by an event of default by Big Rivers. However, although LEM will not be obligated to supply power to Big Rivers from the Station Two Facility, Big Rivers will be required to use power LEM sells to it which is from the Station Two Facility to serve loads located in the two counties subject to the Station Two Facility's two-county restriction.

Maximum and Minimum Hourly and Annual Power Purchase Amounts

The Power Purchase Agreement will establish minimum hourly and annual power purchase amounts which Big Rivers will be required to take and certain maximum hourly and annual power purchase amounts LEM will be required to make available to Big Rivers. These hourly and annual maximum and minimum quantities of power have been established at fixed quantities that change over four separate periods through 2000, 2010, 2011 and thereafter. These quantities are based on Big Rivers' expected load requirements over each year of the LG&E Transaction. See "REORGANIZATION—Agreements Between Big Rivers, the Members, the LG&E Entities and the Smelters" above.

Together, the minimum hourly and annual power purchase amounts and the maximum hourly and annual power purchase amounts will be the "Contract Limits" referred to in the Power Purchase Agreement. Power purchased by Big Rivers in amounts up to the maximum hourly and annual amounts will be referred to as "Base Power." The Power Purchase Agreement establishes the rates for Base Power. During the LG&E Transaction Term, LEM will not provide power at guaranteed rates to Big Rivers above the specified amounts of Base Power. Big Rivers will be responsible for arranging for other deliveries of power (from third-parties or from LEM under a separate agreement) when the hourly and annual maximums are exceeded. However, in addition to Base Power, LEM will provide power to Big Rivers to service its obligations under existing wholesale power sales agreements between Big Rivers and HMP&L, Oglethorpe Power Corporation ("Oglethorpe"), and Hoosier Energy Rural Electric Cooperative, Inc. ("Hoosier" and, collectively with Oglethorpe and HMP&L, the "Existing Off-System Wholesale Power Customers") in exchange for Big Rivers paying to LEM any amounts Big Rivers actually collects for such power.

Subject to the applicable Contract Limits, Big Rivers may schedule and purchase any amount of Base Power from LEM during the LG&E Transaction Term. Although Big Rivers will be required by the minimum hourly power purchase amounts to purchase from LEM the lesser of a stated minimum amount or the amount of power required to meet the Members' full power requirements in each hour (exclusive of the Smelter load) or pay the applicable penalty for amounts not taken, the Power Purchase Agreement does not prevent Big Rivers from paying this penalty in certain hours to purchase lower cost power, if available, from others or reselling a portion of its purchases of Base Power from LEM in other hours (excess to the needs of its Members) to a third-party. Big Rivers also may purchase only its minimum obligation and purchase additional power to meet its Members' loads in excess of the stated minimum from other suppliers (without penalty, provided both hourly and annual minimum obligations are met). As a result, Big Rivers may be able to arbitrage this power purchased from LEM. These arbitrage opportunities will be available in any hour in which Big Rivers' power purchase rate from the market plus any applicable hourly penalty in which such power is not taken is less than the amount which Big Rivers would be charged by LEM at Base Power rates or in which it can resell Base Power at a profit (after transaction costs).

Failure to Purchase Minimum Amounts

If Big Rivers does not purchase an amount of Base Power from LEM equal to or in excess of the minimum annual amount during the course of a year, the Power Purchase Agreement provides that Big Rivers will be deemed to have received a certain percentage of the difference in the amount of power actually purchased from LEM and the minimum annual amount. LEM will bill Big Rivers for such percentage of the shortfall as if Big Rivers had purchased that amount. In effect, this payment will penalize Big Rivers for failing to schedule and purchase such amount of power held in reserve by LEM.

The minimum hourly power purchase amounts will constitute a minimum hourly obligation on Big Rivers equal to the lesser of the actual load in that hour of the Members (exclusive of power supplied by the Members to the Smelters) or the applicable specified minimum hourly amount. In hours where Big Rivers fails to purchase such amount, Big Rivers will be treated as having purchased a certain percentage of the difference between the amount of power actually taken and the applicable minimum. As a result, Big Rivers will pay for such percentage of the minimum required power not taken according to the then-applicable Base Power price. This payment will penalize Big Rivers for failing to purchase power as contracted. In such cases, LEM may resell such excess power in that hour.

To prevent hourly penalties from amounting to more than that which would apply if Big Rivers failed to purchase such power on an annual basis, Big Rivers' cumulative annual obligation for failing to meet minimum hourly and annual power purchase amounts will be limited to a certain percentage of the product of the minimum annual power purchase amount and the applicable Base Power sales rate. In this way, Big Rivers will be protected from excessive hourly minimum take penalties.

Adjustment of Contract Limits

The Power Purchase Agreement will allow Big Rivers, subject to certain limitations, to adjust the Contract Limits downward at any time subsequent to December 31, 1998, by giving written notice to LEM. Contract Limits reductions will be limited to a maximum of 12 MW in any one-year period and a maximum of 72 MW over the term of the Power Purchase Agreement. Any reduction to one of the Contract Limits will be made as a uniform decrease to all four Contract Limits. Once made, any such reduction will remain effective for the balance of the term of the Power Purchase Agreement. No reduction will occur until the expiration of two consecutive full calendar years after notice of such reduction has been given. Further, the minimum annual power purchase amount will not be permitted to be less than 102% of the loads of the Members (excluding the Smelters) in the prior year.

If Big Rivers adjusts the Contract Limits, the other agreements relating to the LG&E Transaction will require a corresponding adjustment that renders WKEC liable for increased rental payments and that renders WKEC liable for an increased portion of the cost of property taxes according to the new ratio of power retained from the Facilities and the Station Two Facility and made available to LEM for sale other than to Big Rivers.

Rates

From the Effective Date through December 31, 2001, the Power Purchase Agreement obligates LEM to offer Big Rivers Base Power in amounts within the Contract Limits at a fixed price of $0.018917 per kWh. Rates will rise annually to $0.020947 per kWh in 2011, before decreasing to $0.020267 per kWh in 2012. Thereafter, rates will again increase annually to $0.023717 per kWh in 2022.

The rates charged by LEM to Big Rivers may be adjusted in 2004, 2011 and 2018 based on the Coal Index (DRI Price of Coal to Electric Utilities - National) and the Labor Index (DRI Unit Labor Cost - National) and the comparison of a calculated reference rate against specified baseline rates set forth in the Power Purchase Agreement. Because the baseline rates will be set at relatively wide ranges, Big Rivers does not anticipate that rates will change dramatically during the term of the Power Purchase Agreement based on adjustments for fuel and labor costs. Consequently, Big Rivers will be liable only for portions of large cost increases and LEM will be liable to reduce prices only in the case of large cost reductions. Big Rivers has estimated that no adjustment would have occurred if the Power Purchase Agreement had been in effect for the seven years prior to 1996.

Relationship with Existing Off-System Wholesale Power Customers

Throughout the LG&E Transaction Term, Big Rivers will remain obligated to supply power under its existing off-system wholesale power contracts with Existing Off-System Wholesale Power Customers. LEM will provide Big Rivers with power over and above Base Power in amounts sufficient to supply these needs during the LG&E Transaction Term. As payment for this power, Big Rivers will pay LEM an amount equal to the net revenues collected by Big Rivers under each of the agreements with the Existing Off-System Wholesale Electric Customers. This power provided by LEM will be in addition to the Contract Limits and will not be used in calculating compliance with annual or hourly minimum or maximum power purchase amounts.

Ancillary Generation Services

Big Rivers will be entitled only to the amounts of power sold to it under the Power Purchase Agreement because Big Rivers will lease the Facilities to WKEC and allow certain of its rights and obligations in the Station Two Facility to be assumed by the Station Two Subsidiary. In order to provide for generation-based ancillary services required to operate the transmission system, LEM has agreed to supply these generation-based ancillary services to Big Rivers for service to the Members and to third-party transmission customers of Big Rivers. With respect to volumes of power to be sold to Big Rivers' Members and the Existing Off-System Wholesale Customers, LEM has agreed to provide certain specified quantities of these generation-based ancillary services to Big Rivers as part of the price of Base Power and power sold by LEM to Big Rivers for subsequent resale to the Existing Off-System Wholesale Customers. With respect to third-party transmission customers and Big Rivers' needs for service to the Members in excess of the specified quantities of such services supplied at no additional charge, LEM has agreed to provide Big Rivers certain generation-based ancillary services needed to support transmission services, at separate cost if not otherwise provided, as needed by Big Rivers in its role as transmission system operator. These services will be provided to Big Rivers at cost-based tariffs which Big Rivers will pass through to its transmission customers as applicable through the Tariff.

Required Regulatory Approvals

The LG&E Transaction will require certain regulatory approvals from FERC and the KPSC prior to the implementation of the LG&E Transaction on the Effective Date.

FERC

Because Big Rivers is a rural electric cooperative with loans from RUS outstanding, Big Rivers is subject to only limited regulation by FERC and is not required to obtain authorization from FERC to perform its obligations under the Lease. Although the LG&E Entities are subject to FERC jurisdiction, the LG&E Entities have requested that FERC disclaim jurisdiction over certain aspects of the LG&E Transaction. On June 29, 1998, FERC issued an order disclaiming jurisdiction over any transfer of assets resulting from the LG&E Transaction and the Station Two Subsidiary's assumption of certain of Big Rivers' rights to operate the Station Two Facility and purchase power from the Station Two Facility that is in excess of the needs of Henderson. WKEC and the Station Two Subsidiary also have obtained approval from FERC to make sales to LEM at market-based rates pursuant to the Federal Power Act ("FPA") which is necessary for WKEC and the Station Two Subsidiary to perform their obligations. In addition, as part of the June 29, 1998 order, FERC accepted LEM's generation-based ancillary services rates.

An order from FERC also is required granting "exempt wholesale generator" status to WKEC. This request was filed April 30, 1998 and amended on May 7, 1998, and June 15, 1998. It will be deemed approved if not acted upon by FERC within 60 days after filing of the last amendment, but WKEC has requested that FERC issue an order no later than July 14, 1998.

KPSC Application

The LG&E Transaction also requires the approval of the KPSC. On June 30, 1997, Big Rivers and the LG&E Entities filed the application to obtain such approval. Specifically, the application requested orders from the KPSC granting (i) approval of the Interim Rates; (ii) approval of the Transaction Rates; (iii) approval of the amendments to the Wholesale Power Contracts; (iv) approval of the LG&E Transaction; and (v) certain other approvals necessary to effectuate the Plan.

On April 30, 1998, the KPSC issued an order with respect to the Application of Big Rivers and affiliates of LEC for approval of the LG&E Transaction and the Transaction Rates. The KPSC approved the LG&E Transaction in principle, subject to review of the final drafts of the transaction documents, but ordered certain modifications to the rate structure for the Smelters and the large industrial customers. The modifications made by the KPSC to the rate structure, along with certain other modifications to the Plan negotiated among the parties, were incorporated into the Plan and accepted by those parties whose consent was required thereunder and approved by the Bankruptcy Court on June 1, 1998.

The KPSC, in its April 30, 1998 order, directed the creation of a new docket (KPSC Case No. 98-267) in which it proposed to review the final drafts of the documents relating to the LG&E Transaction for consistency with the transaction it had approved in principle. The hearing in that case was held on July 6, 1998, and Big Rivers expects an order on or before July 15, 1998.

The KPSC orders approving the LG&E Transaction, including the authorization for Big Rivers to enter into the transaction documents related thereto, are subject to final resolution of any petitions for rehearing and to any appeals. Every order entered by the KPSC continues in force until the expiration of the time, if any, named by the KPSC in the order or until revoked or modified by the KPSC, unless the order is suspended, or vacated in whole or in part, by order or decree of a court of competent jurisdiction.

The two KPSC orders involved in the LG&E Transaction are the order dated April 30, 1998, in P.S.C. Case No. 97-204 (the "April Order"), and the order anticipated to be delivered on or before July 15, 1998, in P.S.C. Case No. 98-267 (the "July Order"). The times for seeking rehearing and for the appeal of the April Order have expired, except to the extent that rehearing granted by the KPSC in that case on June 11, 1998 (the "June Order"), has tolled the time for appeal. In the June Order, the KPSC granted a rehearing on two issues, one of which would be mooted if a favorable order is received in the July Order and the other of which would be mooted by the consummation of the LG&E Transaction in July or August, 1998.

Any party to Case No. 98-267 may seek rehearing by the KPSC of the July Order until thirty days following the issuance of the order. The KPSC must either grant or deny an application for rehearing within twenty (20) days after it is filed, and failure of the KPSC to act upon the application within that period is deemed a denial of the application. If such rehearing were to be granted, the KPSC could change, modify, vacate or affirm its former orders, and make and enter such order as it deems necessary.

Any party to Case No. 98-267 may appeal the July Order by filing an action in the Franklin Circuit Court on or before thirty (30) days following the issuance of the July Order, or within twenty (20) days after its application for rehearing has been denied by failure of the KPSC to act, or within twenty-three (23) days after service by mail of the final order on rehearing, when a rehearing has been granted. The Franklin Circuit Court may vacate or set aside the order or determination of the KPSC on the ground that it is unlawful or unreasonable, may grant injunctive relief in the manner and upon the terms provided by law, and may remand the matter to the KPSC for the taking of newly discovered evidence.

Big Rivers' regulatory counsel is not aware that any party is planning to petition for rehearing or to appeal the April Order or the July Order, and is not aware of any meritorious issue upon which a rehearing or an appeal could be based. Every order entered by the KPSC continues in force until the expiration of the time, if any, named by the KPSC in the order, or until revoked or modified by the KPSC, unless the order is suspended or vacated in whole or in part, by order or decree of a court of competent jurisdiction. Due to the absence of statutory or decisional authority, Big Rivers' regulatory counsel is unable to express any opinion as to the effect which any order resulting from a rehearing or an appeal would have upon the validity of the approvals by the KPSC or the agreements entered into by Big Rivers in reliance upon such approvals and, therefore, upon the validity and enforceability of the agreements entered into by Big Rivers in reliance upon such approvals.

Operations of Big Rivers During the Term of the LG&E Transaction

Throughout the LG&E Transaction Term, Big Rivers will continue to (i) own all the Facilities, (ii) own and operate all its transmission facilities, and (iii) meet the power requirements of its Members and certain third parties (other than with respect to power and energy for the Smelters). Specifically, Big Rivers will retain its existing obligations under the Wholesale Power Contracts with the Members (as modified with respect to termination of Big Rivers' obligation to supply power to the Members for resale to the Smelters). Moreover, Big Rivers will retain all rights arising under existing wholesale power purchase agreements with the Existing Off-System Power Customers (the "Existing Off-System Wholesale Power Contracts") throughout the remaining term of such contracts and certain extensions entered into, consistent with the Power Purchase Agreement. Big Rivers will continue to perform its obligations with respect to the Existing Off-System Wholesale Power Contracts using power purchased from LEM.

From the Effective Date through the expiration of the Electric Service Agreements between Henderson Union and Alcan and between Green River and Southwire on December 31, 2011 and December 31, 2010, respectively, Big Rivers will not supply any power to Henderson Union and Green River for resale to Alcan and Southwire as Tier 1 Demand and Tier 2 Demand. On the Effective Date, LEM will enter into the LEM Wholesale Power Agreements with Henderson Union and Green River to sell power to those Members for resale to Alcan and Southwire, including Tier 3 requirements through a certain date.

Upon expiration of the LG&E Transaction Term, control over the Facilities, together with any capital improvements made during the LG&E Transaction Term which may have been paid for by WKEC, will revert to Big Rivers at no cost. Big Rivers will retain full ownership and control of its transmission facilities at all times during the LG&E Transaction Term. Big Rivers also will retain ownership and control over all of its other assets not subject to the Lease.

Pursuant to the Lease, Big Rivers and the LG&E Entities will work together through a committee structure throughout the LG&E Transaction Term, which, among other things, will make decisions regarding capital expenditures needed to comply with applicable laws and regulations and to maintain the capacity of the Facilities at their current levels. Big Rivers and WKEC each will pay an agreed share of the cost of such capital expenditures at the time such expenditures are made subject to the provisions of the Lease. At the end of the LG&E Transaction Term (or upon the earlier termination of the LG&E Transaction) or upon any sale by Big Rivers of the Facilities, Big Rivers will pay the LG&E Entities an amount based on the remaining value of any assets funded by LG&E.

Financial Information Relating to LEC

LEC files reports and other information with the Securities and Exchange Commission (the "SEC") under the Securities Exchange Act of 1934. Information about LEC is set forth in its Annual Report on Form 10-K for the fiscal year ended December 31, 1997, and its Quarterly Reports for period ended June 30, 1997, September 30, 1997 and March 31, 1998. Copies of these filings can be inspected and copied at the offices of the SEC in Washington D.C., New York, New York and Chicago, Illinois. In addition, the SEC maintains a World Wide Web site (http://www.sec.gov) that contains information statements and other information regarding registrants such as LEC that file electronically with the SEC.

Summary of LG&E Transaction Agreements

Summaries of certain principal agreements relating to the LG&E Transaction are contained in Appendix B to this Remarketing Circular. The agreements summarized include the Participation Agreement, the Power Purchase Agreement, the Lease, the Station Two Agreement, the LEC Guarantee, the LG&E Mortgages and the Nondisturbance Agreement. These summaries do not purport to be complete or definitive and are qualified in their entirety by reference to such documents.

GENERAL

Cooperative Principles

Cooperatives such as Big Rivers are business organizations owned by their members, which are also either their wholesale or retail customers. As nonprofit organizations, cooperatives are intended to provide low cost services to their members, in part by eliminating the need to produce profits or a return on equity. Cooperatives may make sales to non-members, the effect of which is generally to reduce costs to members. Today, cooperatives operate throughout the United States in such diverse areas as utilities, agriculture, irrigation, insurance and credit.

All cooperatives are based on similar business principles and legal foundations. Generally, an electric cooperative designs its rates to recover its cost-of-service and plans to collect a reasonable amount of revenues in excess of expenses (*i.e.*, margins) to increase its patronage capital. Any such margins, which are considered capital contributions from the members, are held for the accounts of the members without interest and returned to them when the board of directors of the cooperative deems it prudent to do so. The timing and amount of any actual return of capital to the members depends on the financial goals of the cooperative and the cooperative's loan and security agreements.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 136) Identify the circumstances that led to Big Rivers owning and operating facilities up to the time of the bankruptcy filing which had excess capacity that was unable to be sold elsewhere, and describe how each of those circumstances have been addressed since then or are otherwise not problematic at the current time.

Response) Please see the response to AG data request Item 135. In 2008 much has changed from the 1980s and 1990s in the electric utility industry. Following the Unwind Transaction closing, Big Rivers would have about 100 Megawatts of surplus capacity. That capacity, when not needed to back-up any other Big Rivers generation off-line at that time, will be sold in the market until such time as native load growth requires it. Today a structured and liquid wholesale power market exists for day ahead and real time trading. Also in existence is a long term wholesale market where longer term sales and purchases can be made.

Witness) Michael H. Core

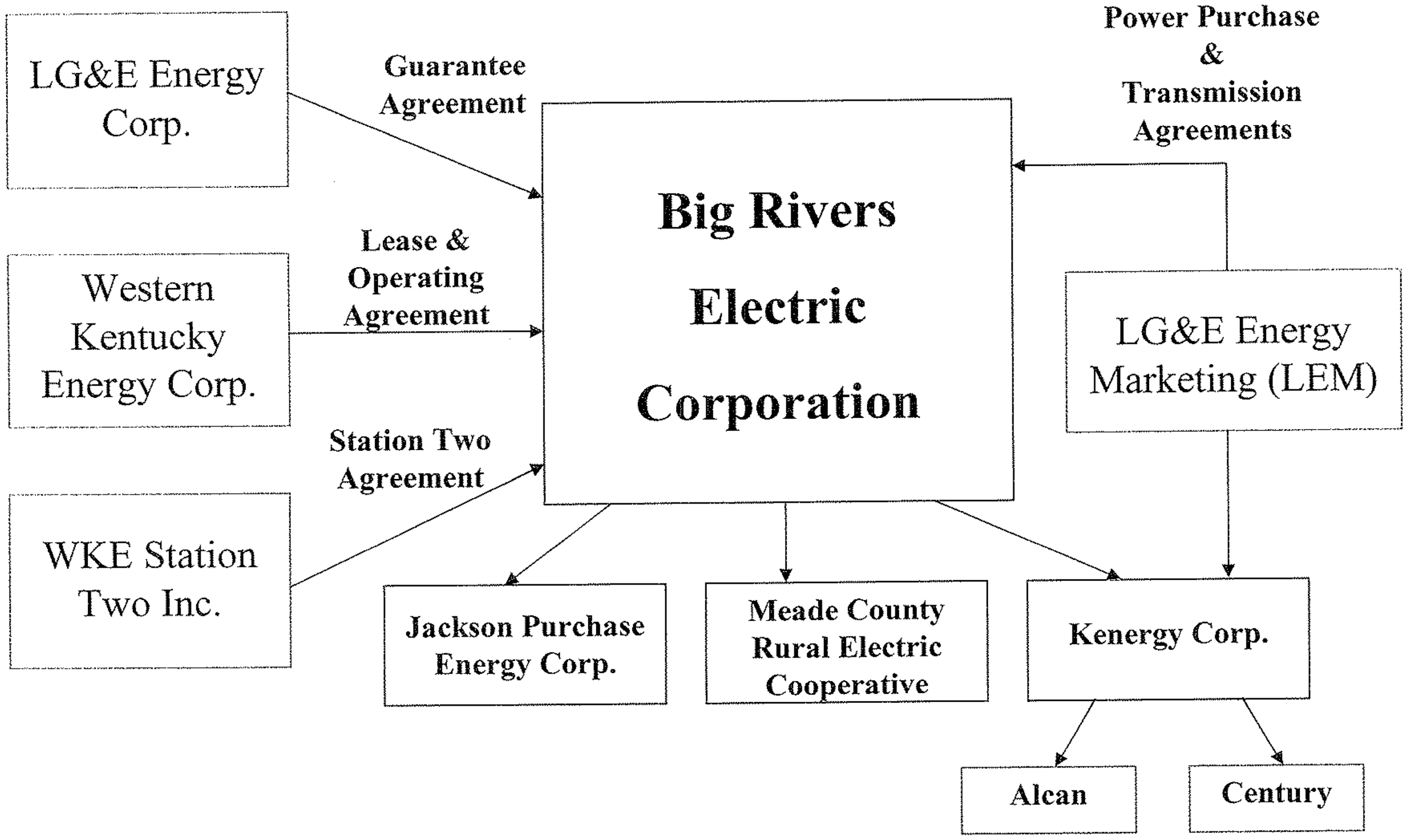
Item 137) Provide a diagram which depicts and describes the relationship of each legal entity including subsidiaries which are involved in the Lease Agreement, and including the City of Henderson/City of Henderson Utility Commission.

Response) See the attached.

Witness) Michael H. Core

Big Rivers Electric Corporation

Big Rivers-E.ON Structure



LG&E Energy Corp.

Guarantee Agreement

Western Kentucky Energy Corp.

Lease & Operating Agreement

WKE Station Two Inc.

Station Two Agreement

Big Rivers Electric Corporation

Power Purchase & Transmission Agreements

LG&E Energy Marketing (LEM)

Jackson Purchase Energy Corp.

Meade County Rural Electric Cooperative

Kenergy Corp.

Alcan

Century

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 138) Provide a diagram which depicts and describes the relationship of each legal entity including subsidiaries which are involved in the Purchase Power Agreement.

Response) Please see the chart on Big Rivers-E.ON Structure provided in response to AG data request Item 137.

Witness) Michael H. Core

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 139) For the most recent three year period, provide graphs which show Big Rivers actual power purchased under the Purchase Power Agreement, versus:

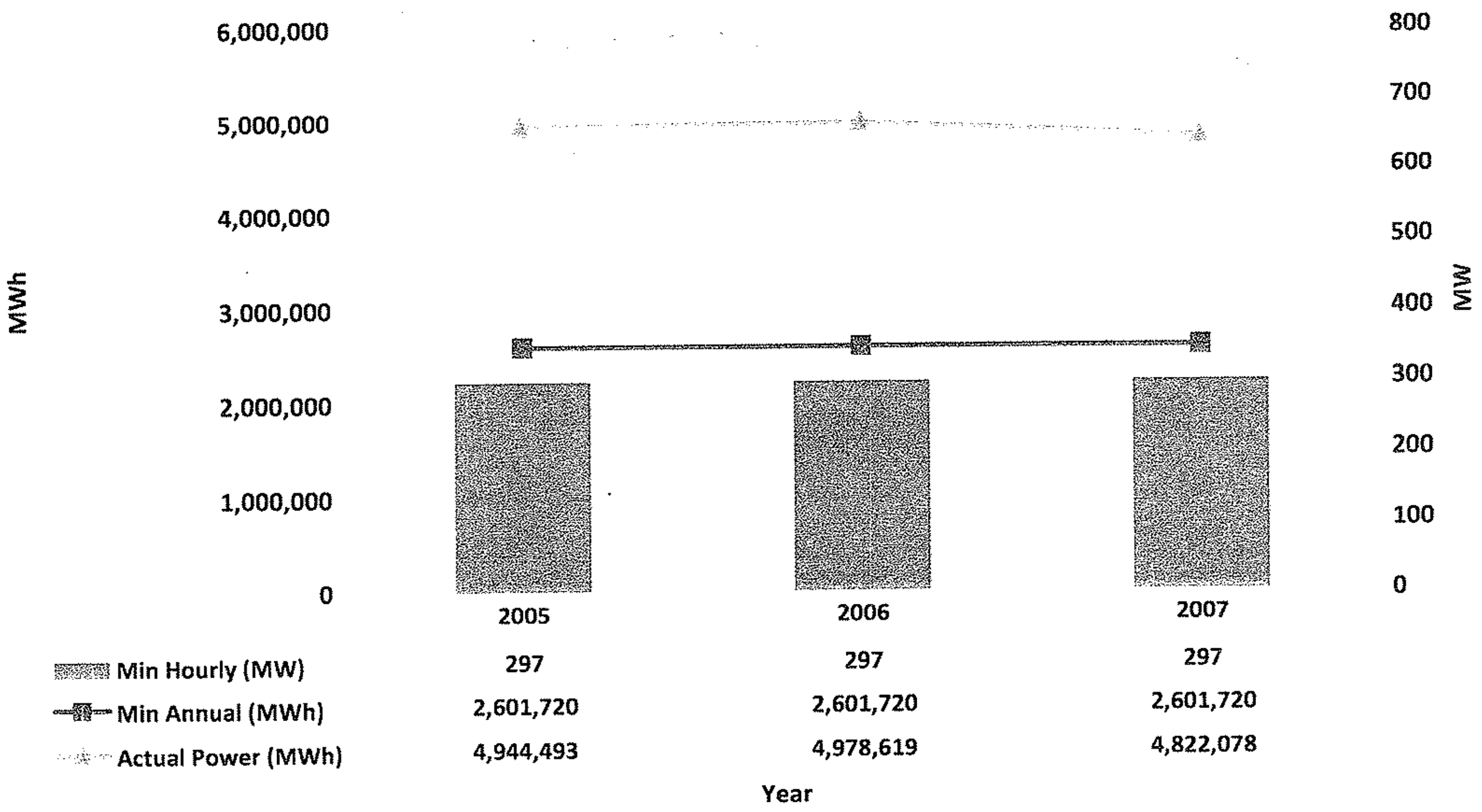
a. Big Rivers' required minimum hourly and annual power purchase amounts; and,

b. The maximum hourly and annual power purchase amounts that LEM is required to make available to Big Rivers.

Response) See attached chart.

Witness) C. William Blackburn

Minimum Purchase Power Amounts



	2005	2006	2007
▨ Min Hourly (MW)	297	297	297
Min Annual (MWh)	2,601,720	2,601,720	2,601,720
Actual Power (MWh)	4,944,493	4,978,619	4,822,078

Item 140) Compare the current minimum hourly and annual purchase power amounts versus those expected to be in effect under the Lease Agreement in:

a. 2011; and

b. 2012.

Response) See attached chart.

Witness) C. William Blackburn

Minimum Purchase Power Amounts

	2008	2011	2012
MIN hourly (MW)	297	517	600
Annual MIN (MWh)	2,608,848	4,528,920	5,270,400

Maximum Purchase Power Amounts

	2008	2011	2012
Max hourly (MW)	597	717	800
Annual MAX (MWh)	5,244,048	6,280,920	7,027,200

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 141) Provide documents (in electronic spreadsheet file format, e.g., .xls) which show on a monthly basis for the past three years, payments (by type, e.g., monthly lease payments, smelter margins, transmission services, and showing any adjustment items separately):

a. To Big Rivers from any E.ON subsidiary or entity under the Lease Agreement;

b. From Big Rivers to any E.ON subsidiary or entity under the Lease Agreement;

c. To Big Rivers from any E.ON subsidiary or entity under the Purchase Power Agreement; and,

d. From Big Rivers to any E.ON subsidiary or entity under the Purchase Power Agreement.

Response) See the attached tables.

Witness) C. William Blackburn

Payment Obligations Between Big Rivers and any E.ON Subsidiary or Entity under the Lease Agreement and Power Purchase Agreement -- 2007:

Description	Jan 2007	Feb 2007	Mar 2007	Apr 2007	May 2007	Jun 2007	Jul 2007	Aug 2007	Sep 2007	Oct 2007	Nov 2007	Dec 2007	Total 2007
Item 141(a) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 2.3.2:													
Monthly Installment of Annual Rental Payments	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	30,964,888.80
Monthly Margin Payments	1,410,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	1,418,000.00	17,008,000.00
Lease Agreement -- Article 2.3.3:													
Incremental Environmental O&M									188,104.61				188,104.61
Item 141(b) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 8.3:													
Monthly Payment -- Capital Budget Amount	547,674.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	547,666.00	6,572,000.00
Item 141(c) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Automatic Reserve Sharing -- Section 6.2(g)	61,617.26	66,900.00	89,000.00	160,100.00	166,800.00	111,500.00	114,700.00	171,468.31	4,375.91	18,800.00	479,211.86	461,162.74	1,905,636.08
Power Purchase Agreement -- Section 6.6:													
Transmission Use Credit -- Section 6.6(c)		376,995.19											376,995.19
Item 141(d) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Base Power - Firm Energy	8,230,105.35	8,353,517.21	7,691,358.82	8,196,161.31	7,899,635.00	7,619,162.26	7,480,970.59	7,830,722.42	8,646,305.57	7,620,895.61	8,050,951.83	8,159,170.86	95,778,956.83
Ancillary Services - Alcan/Century	83,599.70	75,548.73	79,520.25	76,088.93	80,669.36	64,009.68	98,923.54	105,463.33	117,997.32	107,798.99	162,221.44	102,367.27	1,154,208.54
Automatic Reserve Sharing -- Section 6.2(f)	18,600.00	11,000.00	31,100.00	8,400.00	4,500.00	18,900.00	14,900.00	38,160.20	18,214.41	68,210.25	12,000.00	27,067.53	271,052.39
HMP&L Obligation		200.00	11,728.62		400.00	33,327.08	111,396.79	169,607.23	80,014.34	129,472.73	1,499,613.40	269,589.90	2,305,350.09
Other Charges:													
Ancillary Services - Domtar/Weyerhaeuser	20,943.30	19,878.60	21,310.38	16,072.14	19,604.76	19,144.86	19,671.12	18,684.96	19,085.22	18,917.22	18,666.90	19,536.30	231,515.76
Ancillary Services - Big Rivers - Sch. 5 & 6	74,760.00	74,760.00	74,340.00	35,280.00	18,900.00	37,800.00	35,280.00	34,860.00	55,440.00	37,800.00	2,100.00	14,700.00	496,020.00
Energy Imbalance for Domtar/Weyerhaeuser	29,832.71	17,772.36	40,635.87	4,873.30	9,615.07	20,980.12	18,681.81	25,833.47	54,587.41	12,740.91	1,356.75	27,537.05	264,446.83
Adjustments:													
FERC Order--ARS Refund March 2006 -- LG&E	69,943.27												69,943.27
FERC Order--ARS Refund March 2006 -- SIGECO	11,274.23												11,274.23

Payment Obligations Between Big Rivers and any E.ON Subsidiary or Entity under the Lease Agreement and Power Purchase Agreement -- 2006:

Description	Jan 2006	Feb 2006	Mar 2006	Apr 2006	May 2006	Jun 2006	Jul 2006	Aug 2006	Sep 2006	Oct 2006	Nov 2006	Dec 2006	Total 2006
Item 141(a) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 2.3.2:													
Monthly Installment of Annual Rental Payments	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	30,964,888.80
Monthly Margin Payments	1,419,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	1,410,000.00	16,929,000.00
Lease Agreement -- Article 2.3.3:													
Incremental Environmental O&M												241,184.35	241,184.35
Item 141(b) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 8.3:													
Monthly Payment -- Capital Budget Amount	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,583.00	535,587.00	6,427,000.00
Item 141(c) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Automatic Reserve Sharing -- Section 6.2(g)	28,950.04	274,361.75	232,891.95	66,427.18	521,898.63	136,679.02	37,919.39	72,296.34	38,762.89	97,033.53	30,581.95	146,815.07	1,684,617.74
Power Purchase Agreement -- Section 6.6:													
Transmission Use Credit -- Section 6.6(c)				270,626.98									270,626.98
Item 141(d) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Base Power - Firm Energy	8,512,980.35	8,397,511.55	7,687,310.26	8,378,181.12	7,967,241.08	8,199,549.46	7,874,953.38	8,218,997.14	8,306,280.37	7,795,440.16	8,356,404.10	7,952,599.09	97,647,448.06
Ancillary Services - Alcan/Century	45,363.32	71,565.94	75,610.36	87,828.53	82,610.06	62,108.78	85,426.68	97,487.70	125,787.56	58,097.49	89,845.98	80,944.30	962,676.70
Automatic Reserve Sharing -- Section 6.2(f)	26,534.00	3,000.00	6,100.00	13,025.89	8,000.00	18,793.62	42,700.00	17,629.19	9,326.75	170,300.00	17,600.00	6,800.00	339,809.45
HMP&L Obligation	256,106.04				4,289.01	1,937.20	15,302.06	7,820.80	3,768.71				289,223.82
Other Charges:													
Ancillary Services - Domtar/Weyerhaeuser	21,460.74	18,792.06	21,060.90	20,289.36	20,166.30	20,162.10	18,503.52	19,164.60	19,626.18	18,827.34	18,541.74	19,738.74	236,333.58
Ancillary Services - Big Rivers - Sch. 5 & 6	45,360.00	69,300.00	65,100.00	40,320.00	39,480.00	49,980.00	68,040.00	74,760.00	74,760.00	34,020.00	63,420.00	32,340.00	656,880.00
Energy Imbalance for Domtar/Weyerhaeuser	27,706.55	69,178.05	33,970.23	31,180.76	34,968.46	83,889.33	127,547.97	129,406.60	29,384.03	44,312.09	10,733.21	11,407.34	633,684.62
Adjustments:													
FERC Order--ARS Refund Sept. 2005 through Feb. 2006 -- LG&E					450,693.28								450,693.28

Payment Obligations Between Big Rivers and any E.ON Subsidiary or Entity under the Lease Agreement and Power Purchase Agreement -- 2005:

Description	Jan 2005	Feb 2005	Mar 2005	Apr 2005	May 2005	Jun 2005	Jul 2005	Aug 2005	Sep 2005	Oct 2005	Nov 2005	Dec 2005	Total 2005
Item 141(a) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 2.3.2:													
Monthly Installment of Annual Rental Payments	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	2,580,407.40	30,964,888.80
Monthly Margin Payments - LEM Payment to RUS	1,423,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	1,419,000.00	17,032,000.00
Lease Agreement -- Article 2.3.3:													
Incremental Environmental O&M												231,545.27	231,545.27
Item 141(b) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Lease Agreement:													
Lease Agreement -- Article 8.3:													
Monthly Payment -- Capital Budget Amount	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	491,000.00	5,892,000.00
Item 141(c) -- Payments to Big Rivers from any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Automatic Reserve Sharing -- Section 6.2(g)	254,359.90	39,282.87	83,176.22	57,331.73	16,640.06	195,867.84	30,003.10	71,129.76	353,707.16	56,869.68	188,694.88	1,048,784.71	2,395,847.91
Power Purchase Agreement -- Section 6.6:													
Transmission Use Credit -- Section 6.6(c)		318,895.46											318,895.46
Item 141(d) -- Payments from Big Rivers to any E.ON subsidiary or entity under the Purchase Power Agreement:													
Power Purchase Agreement -- Section 6.2:													
Base Power - Firm Energy	7,982,887.68	8,000,252.81	7,312,772.49	8,182,838.57	7,797,117.89	7,884,885.74	7,760,246.34	8,149,711.39	8,336,109.58	7,918,184.03	8,351,015.09	8,133,290.04	95,809,311.65
Ancillary Services - Alcan/Century	60,058.62	43,258.70	41,599.64	44,371.85	43,943.60	64,279.02	80,325.46	80,271.71	47,609.42	57,932.76	50,474.79	43,302.23	657,427.80
Automatic Reserve Sharing -- Section 6.2(f)	22,629.20	9,400.00	12,700.00	31,171.16	14,700.00	51,100.00	20,200.00	8,800.00	19,212.52	12,500.00	21,256.35	42,900.00	266,569.23
HMP&L Obligation	185,869.37	85.53					1,375.29	18,210.10	16,314.87	23,609.24			245,464.40
Other Charges:													
Ancillary Services - Domtar/Weyerhaeuser	19,464.25	21,183.49	21,049.54	20,095.32	19,094.46	18,426.24	18,426.24	17,868.90	18,360.30	17,319.54	17,040.66	18,013.38	226,342.32
Ancillary Services - Big Rivers - Sch. 5 & 6	71,400.00	74,760.00	63,000.00	54,600.00	25,200.00	50,400.00	42,000.00	74,760.00	74,760.00	60,900.00	41,580.00	38,640.00	672,000.00
Energy Imbalance for Domtar/Weyerhaeuser	12,466.71	11,537.88	20,543.64	10,128.95	36,776.82	27,654.98	129,424.48	74,907.78	34,545.06	39,689.31	24,249.31	18,310.41	440,235.33
Adjustments:													

Item 142) Provide documents which show comparison of Big Rivers in size compared to other entities operating generation and transmission facilities, based on:

a. Net assets;
b. Revenues;
c. Number of residential customers served;
d. Generation capacity; and,
e. Capitalization.

Response) The attached schedule provides a comparison of Big Rivers to other entities operating generation and transmission facilities, based on:

a. Total assets;
b. Total Operating Revenues;
c. Number of ultimate customers served;
d. Generation capacity;
e. Total Debt; and,
f. Equity Ratio.

Big Rivers does not have access to information for net assets and total capitalization for other entities operating generation and transmission facilities.

Witness) C. William Blackburn

Comparison of Generation and Transmission (G&T) Cooperatives:

G&T Cooperative	Total Assets	Total Operating Revenue	Number of Ultimate Customers Served	Generation Capacity MW	Total Debt	Equity Ratio
Alabama Electric Cooperative, Inc.	1,199,933,625	617,660,934	399,800	1,724	913,961,412	9.28%
Allegheny Electric Cooperative, Inc.	360,495,996	180,062,423	223,000	256	189,721,400	11.50%
Arizona Electric Power Cooperative, Inc.	279,561,295	NA	200,000	597	195,415,425	NA
Arkansas Electric Cooperative Corporation	1,117,608,500	605,562,276	470,000	2,638	537,788,745	37.67%
Associated Electric Cooperative, Inc.	1,821,765,076	867,142,524	850,000	4,758	1,030,129,726	16.39%
Basin Electric Power Cooperative	2,879,776,889	628,716,081	998,000	2,499	1,376,865,167	26.93%
Big Rivers Electric Corporation	1,254,388,832	230,236,571	109,979	1459*	1,218,135,347	-17.33%
Brazos Electric Cooperative, Inc.	1,493,901,731	880,892,682	439,364	1,567	985,388,366	13.93%
Buckeye Power, Inc.	923,957,611	354,577,815	373,800	1,488	373,603,060	35.75%
Central Electric Power - Missouri	193,552,854	116,090,344	170,000	67	75,004,671	52.80%
Central Electric Power - South Carolina	193,755,837	775,455,976	502,665	0	83,093,278	9.89%
Central Iowa Power Cooperative	462,198,104	140,111,115	127,000	393	298,516,814	16.80%
Central Power Electric Cooperative, Inc.	67,247,345	47,919,538	50,834	0	32,421,861	40.61%
Chugach Electric Association, Inc.	563,040,148	267,542,713	208,213	530	364,532,099	30.05%
Corn Belt Power Cooperative	308,028,349	83,914,575	37,706	251	176,887,184	14.79%
Dairyland Power Cooperative	945,788,755	284,439,111	244,726	1,110	586,499,324	12.46%
Deseret G&T Cooperative	474,944,836	218,755,725	52,680	550	318,334,595	20.42%
East Kentucky Power Cooperative	2,028,501,182	650,959,941	504,492	2,296	1,702,086,944	5.28%
East River Electric Power Cooperative, Inc.	181,601,804	85,727,358	93,000	1,556	94,755,136	34.33%
Golden Spread Electric Cooperative	341,107,480	436,106,124	202,000	0	152,796,433	37.05%
Great River Energy	1,980,916,000	710,031,000	626,545	2,600	1,469,885,554	11.85%
Hoosier Energy Rural Electric Cooperative, Inc.	1,042,444,450	441,344,744	276,742	1,670	808,584,000	11.36%
KAMO Electric Cooperative, Inc.	404,848,990	226,746,915	319,000	200	232,274,256	26.55%
Kansas Electric Power Cooperative, Inc.	206,069,092	110,774,319	105,000	71	153,434,985	9.46%
M & A Electric Cooperative, Inc.	85,287,830	57,085,676	83,372	0	33,476,528	54.17%
Minnkota Power Cooperative, Inc.	206,481,413	155,275,887	112,498	550	95,254,151	37.15%
N.W. Electric Power	120,032,300	59,481,148	69,138	0	33,787,510	43.14%
Nebraska Electric G&T Cooperative	15,676,770	132,859,511	144,652	0	NA	5.26%
North Carolina Electric Membership Corporation	1,307,077,135	911,164,597	880,000	662	1,025,798,874	2.18%
Northeast Missouri Electric Power Cooperative	60,863,369	44,069,475	55,584	0	18,531,987	60.57%
Northeast Texas Electric Cooperative, Inc.	229,922,952	162,445,290	133,000	282	138,897,944	31.41%
Northwest Iowa Power Cooperative	65,981,341	39,732,057	30,714	31	23,594,434	35.28%
Oglethorpe Power Corporation	4,901,745,000	1,128,879,000	1,600,000	4,744	3,402,094,000	12.30%
Old Dominion Electric Cooperative	1,627,409,000	817,515,000	535,000	2,019	NA	18.01%
PNGC Power	36,657,744	167,056,500	165,000	0	NA	45.17%
Rayburn Country Electric Cooperative, Inc.	78,115,620	222,652,052	181,385	0	20,837,729	NA
Rushmore Electric Power Cooperative, Inc.	25,020,998	30,067,606	52,176	0	NA	88.75%
Saluda River Electric Cooperative	166,847,566	156,670,095	170,000	228	332,512,352	NA
Sam Rayburn G&T Electric Cooperative, Inc.	62,412,711	94,558,537	80,012	55	36,417,637	27.01%
San Miguel Electric Cooperative, Inc.	229,949,694	104,447,074	NA	391	170,226,076	10.89%
Seminole Electric Cooperative, Inc.	1,410,567,844	1,173,424,620	880,000	2,222	1,183,706,261	6.96%
Sho-Me Power Electric Cooperative	261,235,992	169,119,453	250,000	3	111,344,105	47.53%
South Mississippi Electric	1,011,163,017	636,991,811	390,499	1,578	722,964,790	11.03%
South Texas Electric Cooperative, Inc.	335,644,754	150,150,084	192,845	233	256,171,766	18.19%
Southern Illinois Power Cooperative	341,795,877	123,818,641	76,817	433	280,327,488	13.14%
Soyland Power Cooperative, Inc.	84,224,676	84,950,951	79,000	176	48,323,194	18.50%
Square Butte Electric Cooperative	359,537,035	89,722,827	95,000	432	303,742,814	6.29%
Sunflower Electric Power Corporation	348,546,027	140,835,920	53,463	594	357,333,049	-19.06%
Tex La Electric Cooperative of Texas	170,422,672	88,916,048	156,424	0	138,902,920	12.74%
Tri-State G&T Association, Inc.	2,471,415,634	846,044,628	578,417	2,451	1,772,601,989	15.12%
Upper Missouri G&T	30,258,136	45,042,736	40,406	0	8,876,421	53.65%
Wabash Valley Power Association, Inc.	488,407,378	569,041,251	364,754	425	330,625,388	12.23%
Western Farmers Electric Cooperative	790,728,459	402,149,402	258,130	1,128	620,706,240	11.95%
Wolverine Power Supply Cooperative	223,598,350	195,689,229	210,763	237	90,570,413	47.46%

* Big Rivers currently owns 1,459 MW of electric generating facilities and has rights to the HMP&L Station Two facility. All of these facilities and rights are currently leased to certain affiliates of E.ON U.S.

Source: G&T Accounting & Finance Association Annual Directory - June 2007 (2[illegible] ta)

Item 143) Please refer to Exhibit 40, page 42. Please provide a document which updates this "average residential rate" comparison for the entities depicted to the current time.

Response) The following information is a comparison of residential electric bills as of July 01, 2006:

Company	Cents per kWh
Kenergy	6.468
Jackson Purchase	6.429
Meade County	6.419
Louisville Gas & Electric	6.783
Kentucky Utilities	5.960
American Electric Power	7.582
Duke Kentucky	6.935

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 144) Please refer to Exhibit 40, pages 44-47. Please provide documents which update the statistics in each table to include the years 2005-2007.

Response) Attached are documents which update the statistics in each table, on pages 44-47 of Exhibit 40, to include the years 2005-2007.

Witness) C. William Blackburn

The following documents update the tables in Exhibit 40, pages 44-47.

Table 1
SELECTED STATISTICS OF EACH MEMBER
(as of December 31)

	Kenergy	Meade	Jackson Purchase
2007			
Avg. Monthly Residential Rev. ($) ...	4,170,143	1,831,843	2,141,500
Avg. Monthly kWh..........................	64,058,176	29,264,254	34,553,055
Avg. Residential Rev. (cents/kWh)...	6.51	6.26	6.20
Times Interest Earned Ratio	1.59	1.54	1.31
Equity/Assets...................................	25%	29%	39%
Equity/Total Capitalization	30%	31%	43%
2006			
Avg. Monthly Residential Rev. ($) ...	3,662,989	1,691,448	1,987,332
Avg. Monthly kWh..........................	59,246,088	26,795,891	31,904,583
Avg. Residential Rev. (cents/kWh)...	6.18	6.31	6.23
Times Interest Earned Ratio	.70	1.50	.96
Equity/Assets...................................	25%	29%	39%
Equity/Total Capitalization	31%	32%	42%
2005			
Avg. Monthly Residential Rev. ($) ...	3,776,928	1,703,018	2,041,414
Avg. Monthly kWh..........................	61,038,775	27,085,249	32,891,128
Avg. Residential Rev. (cents/kWh)...	6.19	6.29	6.21
Times Interest Earned Ratio	1.35	1.71	1.72
Equity/Assets...................................	27%	31%	41%
Equity/Total Capitalization	33%	34%	45%

Table 2
AVERAGE NUMBER OF CONSUMERS SERVED BY EACH MEMBER PER MONTH BY CONSUMER CLASS
(Year ended December 31)

	Kenergy	Meade	Jackson Purchase
2007			
Residential Service	44,758	25,453	25,782
Commercial & Industrial	9,503	2,041	2,952
Other	76	6	13
Total Consumers Served	54,337	27,500	28,747
2006			
Residential Service	44,420	25,001	25,608
Commercial & Industrial	9,364	2,001	2,840
Other	76	6	13
Total Consumers Served	53,860	27,008	28,461
2005			
Residential Service	45,016	24,532	25,330
Commercial & Industrial	8,174	1,977	2,764
Other	74	6	11
Total Consumers Served	53,264	26,515	28,105

Table 3
ANNUAL MWh SALES BY CONSUMER CLASS OF EACH MEMBER
(Year ended December 31)

	Kenergy	Meade	Jackson Purchase
2007			
Residential Service	768,698	351,171	414,637
Commercial & Industrial	8,602,978	101,494	265,115
Other	1,583	1,003	1,657
Total MWh Sales	9,373,259	453,668	681,409
2006			
Residential Service	710,953	321,551	382,855
Commercial & Industrial	8,666,412	94,473	246,707
Other	1,512	1,006	649
Total MWh Sales	9,378,877	417,030	630,211
2005			
Residential Service	732,465	325,023	394,694
Commercial & Industrial	8,614,052	95,009	252,991
Other	1,523	992	676
Total MWh Sales	9,348,040	421,024	648,361

Table 4
ANNUAL REVENUES BY CONSUMER CLASS OF EACH MEMBER
(Year ended December 31)

	Kenergy	Meade	Jackson Purchase
2007			
Residential Service........................	$50,041,715	$21,982,113	$25,697,996
Commercial & Industrial..............	304,081,544	6,857,483	13,587,009
Other..	219,014	64,438	87,394
Total Electric Sales	$354,342,273	$28,904,034	$39,372,399
Other Operating Revenue.............	1,531,503	862,710	993,479
Total Operating Revenue	$355,873,776	$29,766,744	$40,365,878
2006			
Residential Service........................	$43,955,864	$20,297,372	$23,847,988
Commercial & Industrial..............	278,405,909	6,473,634	12,532,652
Other..	204,207	64,593	76,728
Total Electric Sales	$322,565,980	$26,835,599	$36,457,368
Other Operating Revenue.............	1,271,597	838,425	939,005
Total Operating Revenue	$323,837,577	$27,674,024	$37,396,373
2005			
Residential Service........................	$45,323,132	$20,436,215	$24,496,967
Commercial & Industrial..............	242,478,758	6,426,897	12,370,027
Other..	204,262	63,857	76,537
Total Electric Sales	$288,006,152	$26,926,969	$36,943,531
Other Operating Revenue.............	1,258,706	830,085	981,669
Total Operating Revenue	$289,264,858	$27,757,054	$37,925,200

Table 5
SUMMARY OF OPERATING RESULTS OF EACH MEMBER
(Year ended December 31)

	Kenergy	Meade	Jackson Purchase
2007			
Operating Revenue & Patronage Capital	$355,873,776	$29,766,744	$40,365,878
Depreciation & Amortization......................	7,415,079	2,702,559	3,433,896
Other Operating Expenses...........................	340,042,623	23,911,521	33,968,199
Electric Operating Margin	$8,416,074	$3,152,664	$2,963,783
Other Income..	1,256,081	363,626	597,872
Gross Operating Margin	$9,672,155	$3,516,290	$3,561,655
Interest on Long-term Debt (1)	5,703,124	2,222,123	2,615,535
Tax Expenses..	295,302	34,075	43,167
Other Deductions..	266,780	49,369	82,890
Net Margins	$3,406,949	$1,210,723	$820,063
2006			
Operating Revenue & Patronage Capital	$323,837,577	$27,674,024	$37,396,373
Depreciation & Amortization......................	6,227,515	2,497,883	3,235,100
Other Operating Expenses...........................	314,562,583	22,505,681	32,190,244
Electric Operating Margin	$3,047,479	$2,670,460	$1,971,029
Other Income..	1,059,898	400,563	691,939
Gross Operating Margin	$4,107,377	$3,071,023	$2,662,968
Interest on Long-term Debt (1)	5,183,057	1,990,026	2,660,517
Tax Expenses..	271,795	33,909	41,657
Other Deductions..	246,961	45,024	68,334
Net Margins	($1,594,436)	$1,002,064	($107,540)
2005			
Operating Revenue & Patronage Capital	$289,264,858	$27,757,054	$37,925,200
Depreciation & Amortization......................	5,752,782	2,318,515	3,131,797
Other Operating Expenses...........................	278,462,306	22,513,231	31,401,810
Electric Operating Margin	$5,049,770	$2,925,308	$3,391,593
Other Income..	1,056,598	240,975	525,021
Gross Operating Margin	$6,106,368	$3,166,283	$3,916,614
Interest on Long-term Debt (1)	4,138,546	1,808,023	2,211,585
Tax Expenses..	269,762	25,105	40,996
Other Deductions..	207,552	58,070	76,581
Net Margins	$1,490,508	$1,275,085	$1,587,452

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(1) Interest on Long-Term Debt is net of interest charged to construction.

Table 6
CONDENSED BALANCE SHEET INFORMATION OF EACH MEMBER
(as of December 31)

	Kenergy	Meade	Jackson Purchase
2007			
ASSETS			
Total Utility Plant (1)	$224,786,800	$83,626,010	$113,200,271
Depreciation	53,319,541	20,865,845	34,096,756
Net Plant	$171,467,259	$62,760,165	$79,103,515
Other Assets	53,037,690	8,677,372	9,790,190
Total Assets	$224,504,949	$71,437,537	$88,893,705
EQUITY & LIABILITIES			
Equity	$55,307,516	$20,828,346	$34,759,030
Long-term Debt	129,556,978	46,264,913	46,768,664
Other Liabilities	39,640,455	4,344,278	7,366,011
Total Equity & Liabilities	$224,504,949	$71,437,537	$88,893,705
2006			
ASSETS			
Total Utility Plant (1)	$217,727,353	$79,489,327	$108,466,681
Depreciation	48,193,715	19,289,710	31,714,276
Net Plant	$169,533,638	$60,199,617	$76,752,405
Other Assets	42,727,209	10,054,371	12,714,096
Total Assets	$212,260,847	$70,253,988	$89,466,501
EQUITY & LIABILITIES			
Equity	$52,548,483	$20,256,300	$34,444,409
Long-term Debt	117,705,836	43,229,316	46,653,947
Other Liabilities	42,006,528	6,768,372	8,368,145
Total Equity & Liabilities	$212,260,847	$70,253,988	$89,466,501
2005			
ASSETS			
Total Utility Plant (1)	$209,103,179	$73,116,639	$101,827,930
Depreciation	45,328,490	17,965,762	29,579,797
Net Plant	$163,774,689	$55,150,877	$72,248,133
Other Assets	40,644,449	10,080,875	11,356,467
Total Assets	$204,419,138	$65,231,752	$83,604,600
EQUITY & LIABILITIES			
Equity	$54,917,697	$19,997,594	$34,568,879
Long-term Debt	113,484,267	38,921,945	41,726,917
Other Liabilities	36,017,174	6,312,213	7,308,804
Total Equity & Liabilities	$204,419,138	$65,231,752	$83,604,600

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(1) Includes construction work in progress.

Item 145) Provide the Examiner's Reports from the Big Rivers Chapter 11 bankruptcy proceeding.

Response) Big Rivers objects to producing the Examiner's reports from its reorganization proceeding on the grounds that they have no relevance to this proceeding, and the Attorney General was a party to that reorganization proceeding and received all documents served on the parties therein. Without waiving its objection, Big Rivers attaches two reports of the Examiner dated November 12, 1996, which contain significant errors. Big Rivers and other parties were prohibited by the bankruptcy judge then sitting on the case from filing objections to the reports. Big Rivers states its belief that all other reports of the Examiner were placed under seal of confidentiality by Honorable Joseph H. McKinley, Jr., of the U. S. District Court for the Western District of Kentucky, Owensboro Division, in U.S. v. Schilling, Case No. 4:99-cv-00117-JHM. This case involved the fee application of the Examiner, including his request for a fee "bonus" for his work in that case. However, the case resulted in orders of the U. S. District Court, affirmed by the U. S. Court of Appeals for the Sixth Circuit, requiring the Examiner to disgorge all fees he was paid during the Big Rivers reorganization proceeding (almost $1 million) because of his inappropriate conduct as Examiner. Please refer to the following opinions for details: In re Big Rivers Elec. Corp., 355 F.3d 415 (6th Cir. 2004); In re Big Rivers Elec. Corp., 284 B.R. 580 (W.D. Ky. 2002).

Witness) Michael H. Core
Counsel

UNITED STATES BANKRUPTCY COURT
WESTERN DISTRICT OF KENTUCKY

IN RE:	)	CHAPTER 11
	)	
BIG RIVERS ELECTRIC CORPORATION,	)	CASE NO. 96-41168
	)	
Debtor,	)	

PRELIMINARY REPORT BY EXAMINER

November 12, 1996

J. Baxter Schilling
1513 South Fourth Street
Louisville, Kentucky 40208
(502) 636-2031
Examiner

recd 11-12-96
bot

I. SCOPE OF PRELIMINARY REVIEW

The Examiner's preliminary investigation (which occurred from October 19 through October 28) consisted of the following:

A. Conducted telephonic or in person meetings with all "Trustee Motion" creditors to ensure that Examiner understood their allegations and any additional allegations of mismanagement or breach of fiduciary duties by the Board of Directors of Big Rivers.

Examiner also held preliminary meetings with attorneys for NSA, Inc. and Alcan Aluminum (the "Smelters"), the four member distribution "Co-ops" and the debtor. The only major participant in the case the Examiner has not held a preliminary meeting with is Pacificorp. One telephonic conference with counsel for one of the unsuccessful bidders for Big Rivers was also conducted.

B. Spent one day reviewing documents in the offices of Sullivan, Mountjoy, Stainback and Miller (herein Sullivan, Mountjoy).

C. Spent two days reviewing documents in the offices of Big Rivers Electric Corp.

D. Estimate of documents reviewed - in excess of 4,000 pages.

E. Sworn statements were taken from:

1. Sandra Wood, Chairperson of Board of Big Rivers
   and President of Corporation

2. Johnny Hamm - Board Member and Secretary of Corporation

3. Al Robison - Acting General Manager

4. Mike Dotson - Vice General Manager of Fuels
   and Environmental Affairs

5. John West - Vice General Manager of Finance

6. Paul Schmitz - Consultant and Former General Manager

7. Tonda Luckett - Supervisor of Internal Audit

II. ALLEGATIONS OF MISMANAGEMENT OR BREACH OF FIDUCIARY DUTIES RAISED BY "TRUSTEE MOTION" CREDITORS.

A. CONFLICT OF INTEREST

1. The Board of Directors of Big Rivers has the duty to maximize value of DIP for the benefit of the creditors versus the competing goal of member Co-ops to obtain cheapest rates possible.

2. Failure to develop all bids in Big Rivers' resolution process.

3. Inherent conflict between Boards of Big Rivers and Co-ops.

B. RELIANCE ON OUTSIDE CONSULTANTS.

1. _Per se_ issue.

2. Failure to take advice when contrary to position Big Rivers wanted to advance.

C. BACKGROUND OF CRIMINAL ACTIVITY.

1. Shaken public confidence.

2. Questionable ability of oversee management.

3. Deliberately ignored corrupt practices.

4. Date the Board knew of corruption.

D. RATE REDUCTION ISSUE.

1. Current financial position of Co-ops.

2. Legitimate business reasons to seek rate reduction.

III. PRELIMINARY FINDINGS RELATING TO ISSUES OF MISMANAGEMENT OR BREACH OF FIDUCIARY DUTIES.

A. CONFLICT OF INTEREST.

There appears to be an actual, rather than just inherent, conflict of interest between the Board of Directors of Big Rivers and the Boards of Directors of the four distribution co-ops. Based on testimony obtained, the Examiner discovered that the by-laws of the corporation allows 2 of the 3 directors that each Co-op places on Big Rivers Board to be "outside" directors. Except for one outside director (Edward Johnson), this does not occur. Even more disturbing to the Examiner is the fact that once the Co-ops determine which members of their Boards will serve on the Big Rivers Board, those members of the Co-ops' Boards do not resign from their respective Co-op Boards when beginning their tenure on the Big Rivers Board. In short, eleven of the twelve Big Rivers Board members are also presently serving (and have been serving during their entire terms) on their respective Cooperative Board of Directors.

A primary interest of the Co-ops is to obtain what they deem to be "competitive" rates. "Competitive" rates is a euphemism for lower rates. The lower the rates, the less likely it is for Big Rivers to pay its debts, in full. Thus, the actual conflict exists.

At the beginning of what the debtor entitled as its "resolution process", the goals stated by Big Rivers were three-fold, (and included the specific goal of finding a solution to its long-term debt). On October 5, 1994, in a list of strengths and weaknesses of Big Rivers, the statement was made: "Certainly Big Rivers should never consider selling its system for its book value or the amount of debt it owes." After consultants were hired it appears the goals shifted and emphasis shifted to the goals of the Co-ops (e.g. lower rates) and protecting Big Rivers' employees. When Requests for Proposals were sent to interested bidders on or about June 14, 1995, no stated goal related to payment in full of creditors (albeit there was a reference to "restore long term financial credibility with its creditors.")

Mr. Robison, the "turnaround specialist" hired by the debtor, had no prior experience in selling a utility company as large as Big Rivers. He had, however, tried unsuccessfully several years earlier to purchase the largest public power utility in New Mexico. While Mr. Robison testified that maximizing the value of the debtor is "implicit" in the goals and objectives which Big Rivers has identified, the Examiner believes, based on his preliminary investigation, that the goals of Big Rivers in the resolution process are those announced, not those that are "implicit"; therefore, it appears that the allegation of the Trustee Motion creditors relating to a conflict of interest may be valid.

B. FAILURE TO DEVELOP BIDS.

The Examiner was informed that several unsuccessful bidders for Big Rivers did not believe the bidding process employed by Big Rivers was fair. There was insufficient time in the preliminary report investigative period to determine whether this allegation had any merit. However, the Examiner did obtain certain evidence relating to the bid process that caused him concern. The Examiner obtained a letter dated December 20, 1995, from one of the unsuccessful bidders, that stated in part: "We understand that you currently have an outstanding debt of approximately 1.25 billion dollars. We are prepared to submit a proposal that would result in full payment of principal and interest to all creditors." Big Rivers' written response to that letter was also given to the Examiner.

The Examiner questioned Mr. Robison and Mrs. Wood about the aforestated December 20 letter. From their statements, the debtor's position is that Big Rivers gave the prospective purchaser another chance in January, 1996, to enhance its original bid, and when that proposal was received it still fell below the original value of the Pacificorp proposal. [The current Pacificorp proposal is valued, on a net present value basis (using a 6.37% discount rate), at approximately $986,000,000, whereas, as explained to the Examiner, the original Pacificorp proposal paid, in full, all creditors (save the RUS which had agreed to a $75,000,000 write-down].

The Examiner has not seen the January, 1996, proposal from the aforestated unsuccessful bidder. However, based on the bidder's statement, the Examiner believes that if this interested party is willing to make a proposal to pay in full the $1.25 billion in debt owed by Big Rivers that proposal should be actively pursued by the DIP, and currently that is not being done.

C. INHERENT CONFLICT BETWEEN BOARDS OF BREC AND BOARDS OF THE FOUR DISTRIBUTION CO-OPS.

This point has been addressed above. Again, based on the preliminary investigation, it appears that there is an actual conflict, not just an inherent conflict. It appears, based on the testimony of Mrs. Wood, that the corporation's by-laws allow it to lessen the inherent conflict by placing two outside directors (of their respective three seats) on the Big Rivers Board. The Co-ops have not done this. Secondly, and more disturbing, is the fact that the Co-op board members who are elected to serve on the Big Rivers Board do not resign their Co-op board seat while serving on the Big Rivers Board of Directors.

D. RELIANCE ON OUTSIDE CONSULTANTS.

The Big Rivers Board has increasingly been relying on outside consultants in its resolution process. This is probably not unexpected since no one on the Board, or in management, has any experience in selling, or otherwise disposing of, a utility corporation as large as Big Rivers. Thus, the Examiner does not believe a per se problem exists just because the debtor has utilized consultants. For instance, the suggestion was made by one or more of the banks in this case that Big Rivers utilize an investment banker to market the property. The RUS opposed this idea. The point is that had an investment banker been involved in the sale there would still be reliance on consultants (the investment banker).

The Examiner does not believe the use of outside consultants is the major problem, albeit the present usage of consultants (as well as the cumulative cost of such consultants) needs further investigation. The problem, from a preliminary review, is that the goals of Big Rivers seem more self-serving rather than geared to obtaining repayment in full of its debts, or at least maximizing value for its creditors.

E. FAILURE TO TAKE CONSULTANTS' ADVICE.

The Examiner's preliminary review was not focused on this issue, therefore, the Examiner cannot, on a preliminary basis, give the Court much guidance on this allegation. (Apparently, the alleged failure to follow consultants' advice relates to a "cost of service" study done by the Brattle Group. This allegation needs to be investigated.)

F. BACKGROUND OF CRIMINAL ACTIVITY.

1. SHAKEN PUBLIC CONFIDENCE.

The Examiner believes that Big Rivers feels under siege on this point, and has attempted to do certain things to restore public confidence. The preliminary review determined that in addition to a substantial public relations campaign, Big Rivers has an "ethics hotline". People can place a call to a telephone number and anonymously report what they consider to be improper or criminal activities of those employed by, or involved with, Big Rivers. These allegations are then investigated.

Much of Big Rivers' poor public image stems from the criminal activities of William Thorpe, the former General Manager of Big Rivers who resigned on June 2, 1992. Mr. Thorpe's criminal activities dealt with certain bribery/kick-back schemes involving fuel procurement by Big Rivers.

The Kentucky Public Service Commission (herein KPSC) ordered an examination of Big Rivers' fuel procurement practices commencing for the period starting November 1, 1990. The KPSC retained Overland Consulting Inc. to undertake that audit. The audit report was issued in May, 1993 (the Overland Audit). Hearings were held before the KPSC in October, 1993, resulting in a finding that certain fuel costs were not reasonable and that a portion of the costs could not be passed on to its customers. The result of the KPSC's ruling was that Big Rivers had to rebate millions of dollars to its customers.

The Overland Audit Report recommends approximately 38 ways in which Big Rivers could improve its fuel procurement policies. The Examiner questioned Mike Dotson, Vice General Manager of Fuels, relating to these recommendations and Mr. Dotson stated that 35 of the recommendations in the Overland Audit Report had been implemented. On three recommendations (which Overland considered to be of "medium" priority), the debtor chose to disagree with the Overland recommendations.

One of the disagreements between Big Rivers and Overland relates to how Big Rivers now accepts bids for coal purchases. All fuel bids are opened in public and the contract goes to the low bidder. (If more coal is needed than the low bidder can supply, then the next low bidder is also selected and the process continues until the entire contract is let). Overland criticized this practice (as did one of the "Trustee Motion" creditors) for it does not allow the debtor to negotiate downward the low bidder price.

The Examiner questioned Mr. Dotson on this point. Mr. Dotson's testimony was that the debtor did not want, because of its past activities, to be involved in influencing any coal contracts. While the Examiner understands fully this conclusion and can appreciate it, there is little question that if the debtor implemented this recommendation of the Overland Audit Report, it could save money in its coal purchases.

2. QUESTIONABLE ABILITY TO OVERSEE MANAGEMENT.

Prior to June, 1992, there is little doubt that the Board did not properly oversee management. This lack of oversight appears due, in part, to the dominance which Morton Holbrook exerted over the Board. It appears that Mr. Holbrook's direct influence continued until sometime in 1994, when he announced his resignation as corporate counsel for Big Rivers.

At the present time, Mrs. Wood is asserting, on behalf of the Board, much more authority than has been asserted in the past. Further investigation is needed to determine whether this additional assertion of authority is sufficient, or whether the main policy making is still being done by management, professionals or consultants, without proper oversight by the Board.

On this point, there is another concern. Of the twelve current Board members, six of the members were on the Board during the tenure of Mr. Thorpe, as General Manager. The ability of these six members, including Mrs. Wood, to oversee properly management is a concern.

Finally, the circumstances under which Paul Schmitz was terminated as General Manager must be reviewed. Mr. Schmitz was given a two year consulting contract beginning October, 1995. The Vice General Managers, who worked with Mr. Schmitz, all spoke very highly of him in their statements to the Examiner. Mr. Schmitz was, in effect, forced to take the "consulting" agreement under questionable pretexts. (He was told to go to the Atlanta office of Big Rivers' legal counsel, Long, Aldridge & Norman, on company-related business. Yet, once there, Schmitz discovered the purpose of the trip was actually to convince him to resign as General Manager, as well as negotiate and execute the consulting agreement and general release). Mr. Schmitz stated this was done because Mrs. Wood (and possibly other individuals) believed he was tainted by association - which means because he was second-in-charge of Big Rivers when Thorpe was General Manager, some people (apparently including Mrs. Wood) thought Mr. Schmitz knew, or should have known, of Thorpe's activities. Mr. Schmitz denied knowing of Thorpe's activities prior to May 12, 1992.

One problem the Examiner has with the handling of Mr. Schmitz is that if the standard used to remove Mr. Schmitz is applied to the Board of Directors, then all six current Board members who were on the Board when Thorpe was General Manager, including Mrs. Wood, should also have been required to resign.

3. DELIBERATELY IGNORED CORRUPT PRACTICES/ BOARD KNOWLEDGE OF CORRUPTION.

These allegations raise great concern with the Examiner. The evidence on this point clearly indicates that for a period of nearly 15 months after allegations of Thorpe's questionable business practices or misconduct were known to certain members of the Board (the Executive Committee), no actions were taken by either corporate counsel, the company's outside auditor or the Executive Committee of the Board to inform the full Board of Thorpe's questionable activities.

It was not until May 22, 1992, that the entire Board of Directors of Big Rivers was first made aware of the allegations relating to Mr. Thorpe.

On June 2, 1992, Mr. Thorpe was allowed to resign as General Manager which resignation was accepted on June 3, 1992.

The evidence is also clear that the current Board of Directors has failed to make an independent investigation of the extent of the fraud, mismanagement, malpractice or criminal activities that existed at Big Rivers notwithstanding evidence does exists that would lead a reasonably prudent board member to conclude that such an independent investigation should be performed, and if actionable conduct is discovered to take the appropriate measures.

Not only has the current Board of Directors failed to make difficult decisions relating to certain of its past professionals, it accepted certain explanations relating to Mr. Thorpe's actions which defy common sense. Specifically, Mrs. Wood testified that she believes Bill Thorpe voluntarily informed Morton Holbrook in 1991 about his $500,000.00 consulting contract with Jim Smith Contracting Co., which contract was entered into in June, 1988. The Examiner's investigation has demonstrated that Mr. Thorpe did not volunteer this information to Mr. Holbrook. Common sense indicates this is an implausible explanation concerning how knowledge of Mr. Thorpe's $500,000.00 consulting contract came to be known by Mr. Holbrook. Notwithstanding the implausibility of this explanation, Mrs. Wood (and apparently the current Board) has chosen to accept this explanation rather than to insist on an independent investigation into all aspects of the Thorpe matter, and how the Thorpe matter was handled by professionals employed by the Board.

On February 16, 1994, the Board of Directors approved a settlement agreement relating to the Green River Coal Company bankruptcy, which settlement was never implemented. In the February 16, 1994 Minutes, the Board approved a post-mortem investigation of Big Rivers fuel practices by an independent and disinterested third party. This investigation never occurred. From the statements taken by the Examiner, the reason this investigation never occurred is because the Smelters backed out of the settlement, and since they were to pay for 75% of the cost of the investigation, it did not occur.

The problem with the aforestated explanation is the following portion of the February 16, 1994 Minutes, which reads: "REA basically told the Executive Committee they were not satisfied with the way Big Rivers had handled the discrepancies found regarding the coal contracts and felt an investigation should be done hiring a disinterested party to get to the bottom of this matter." Thus, based on this statement contained in the minutes, it appears that the REA (now called RUS) wanted this independent investigation regardless of the outcome of the Smelters' litigation.

Another Executive Session of the Board was held on March 4, 1994, which was called specifically to discuss the meeting that had occurred between the Executive Committee, Mr. Gerry Bruen (Special Counsel for the RUS) and Mr. Larry Belluzzo (Program Advisor for the RUS). Mr. Holbrook announced his resignation at this Board meeting, effective on his 80th birthday which was on September 15, 1994. After that announcement was made, there is no further indication in Executive Session Minutes that the RUS insisted that an independent investigation occur.

The manner in which Big Rivers dealt with its outside auditors, KPMG Peat Marwick (herein Peat Marwick), relating to both the Thorpe matters and the

Substitution Coal Agreement with Green River Coal Company also concerns the Examiner.

While it appears that the managing partner of Peat Marwick, Mr. Doug Sumner, may have been the first person to disclose Thorpe's $500,000.00 consulting contract with Jim Smith Contracting Company to corporate counsel for Big Rivers, Mr. Sumner's activities after that disclosure need to be investigated further to determine if any actionable conduct occurred.

In addition, Mr. Sumner's involvement in the Substitute Coal Agreement between Big Rivers and Green River Coal Company needs additional investigation.

There has been no independent investigation of whether any action, or inaction, by Peat Marwick partners or staff in the representation of Big Rivers is actionable. Instead, Big Rivers chose not to continue to retain Peat Marwick as its auditors for work on the 1994 audit and thereafter, notwithstanding Peat Marwick's bid for such work was less than the bid of Arthur Andersen, the accounting firm retained to perform the 1994 audit. Arthur Andersen continues to be the Debtor's outside accountants.

G. IMPROPER RATE REDUCTION.

1. CURRENT FINANCIAL STATUS OF THE CO-OPS.

There are four distribution cooperatives that form the Big Rivers' System.

These cooperatives are Meade County Rural Electric Cooperative Corp. (herein Meade County Co-op), Jackson Purchase Electric Cooperative Corporation (herein Jackson Purchase Co-op), Henderson Union Rural Electric Cooperative Corp. (herein Henderson Union Co-op) and Green River Electric Corp. (herein Green River Corp.).

Financial statements for the four Co-ops were requested by the Examiner for a 5 year period from 1991 through 1995. The debtor produced the so-called RUS Form 7 in response to that request. Mr. John West, Vice General Manager - Finance for Big Rivers, testified relating to these financial statements. Mr. West stated he was not entirely familiar with the Form 7 filed by the various member Co-ops.

Mr. West did acknowledge that the Co-ops in the last 5 years have all made money. In contrast, in the last 5 years Big Rivers has lost approximately $30,000,000 per year.

Since Big Rivers and the four member cooperatives are all non-profit corporations some of the accounting terms are different than normally understood. For instance, instead of using the phrase retained earnings, the cooperative financial statements use the term patronage capital. Earnings are apparently called Operating Margins.

Big Rivers has a negative patronage capital account in excess of $300,000,000. In contrast, as will now be demonstrated, all of Big Rivers' distribution co-ops have positive patronage capital. In fact, one Co-op has recently declared a patronage dividend to its customers.

Green River Corp had patronage capital at the end of 1995 of at least $48,020,400. Jackson Purchase Co-op had patronage capital at the end of 1995 of at least $21,167,921. Meade County Co-op had patronage capital at the end of 1995 of at least $11,989,701. Henderson Union Cooperative's Form 7 was not complete, however, from the balance sheet contained in Form 7, it appears that Henderson Union Co-op's patronage capital in 1995 was approximately $35,850,371. In short, the combined patronage capital of the four distribution cooperatives is in excess of $116,000,000. In contrast, Big Rivers had negative patronage capital of approximately $300,000,000.

During Mr. Robison's statement, the Examiner discovered that Big Rivers projects that if its proposed plan of reorganization is confirmed by the Court at the end of the 25 year term the four distribution cooperatives patronage capital accounts will exceed $134,700,000. The Banks believe the Co-ops patronage capital account at the end of the 25 year lease will be in excess of $500,000,000.

2. RATE REDUCTION.

The debtor's plan calls for rate reductions for all customers. By far, the largest users of Big Rivers' power are the Smelters, which, as stated above, are NSA and Alcan Aluminum. Combined these two Smelters use 65-70%

of all power generated by Big Rivers' system. The other users of Big Rivers power are referred to as the "Rurals" and "Other Industrials", and combined the debtor has approximately 90,000 users of its power.

The current rate reduction from existing rates called for in the plan is substantial. The rate reductions, if approved, will not produce sufficient revenues to pay all of Big Rivers creditors in full. In fact, under the reduced rate structure the present value of Big Rivers cash flow over the next 25 years is expected to be approximately $986,000,000.00, whereas its debts are approximately $1.25 billion.

If there were no rate reductions, the Examiner believes that all creditors would be paid in full. Also, small rate reductions to the Co-ops and somewhat larger rate reductions for the Smelters still provide sufficient cash flow to pay all the debtor's debts.

IV. CONCLUSION.

Based on the findings contained in this Preliminary Report, the Examiner believes that many of the allegations raised by the "Trustee Motion" creditors may be valid and warrant further investigation.[1]

J. Baxter Schilling
Examiner

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[1] At the instruction of the Court, the Examiner is filing this edited version of the Examiner's Preliminary Report, which unedited version was presented to Judge Roberts, *in camera*, on October 29, 1996.

UNITED STATES BANKRUPTCY COURT
FOR THE
WESTERN DISTRICT OF KENTUCKY

IN RE:) CHAPTER 11
)
BIG RIVERS ELECTRIC CORPORATION) CASE NO. 96-41168
)
Debtor)
)

EXAMINER'S REPORT TO COURT ON DEBTOR'S NOTICE TO FILE A RATE CASE

The Court has instructed the Examiner to file, on Tuesday, November 12, a Report to the Court relating to the debtor's Notice to file a rate case. This Report is being filed to comply with the Court's directive.

The Examiner believes the Court should consider the following factors before it determines what Orders, if any, it should enter relating to the Notice filed by the debtor-in-possession (herein Big Rivers, or DIP) that it intends to file a rate case at the Kentucky Public Service Commission (KPSC), which rate case the debtor has agreed, pursuant to the Examiner's moratorium, would not be filed before December 2, 1996.

The factors discussed below are not set forth in order of importance, and no weight should be applied to any factor solely because of the order in which it is presented.

A. DEBTOR'S ABILITY TO COMPLY WITH AGREEMENTS AND FILE PLAN OF REORGANIZATION

1. If Big Rivers does not file its rate case on December 2, 1996, it may not be able to comply with the terms and

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conditions of its Omnibus Agreement with Pacificorp Holdings, Inc. (herein Pacificorp). The Examiner at this time cannot advise the Court whether the Pacificorp deal maximizes the value of the debtor for its creditors. If the Pacificorp deal is, in fact, the best value for the debtor, and it cannot be consummated because of the debtor's inability to establish its proposed rates, then the value of the debtor may be lessened, which will adversely affect primarily the RUS.

2. If Big Rivers does not file its rate case on December 2, 1996, it may violate certain agreements it has with NSA, Inc., and Alcan Aluminum (herein Smelters).

3. Big Rivers' rate case to be filed at the KPSC, as disclosed to the Examiner, as well as the lease payments from Pacificorp, would form the basis of its plan of reorganization, producing the stream of payments into the future from which to pay certain of its debts. If the DIP does not file its rate case, its plan, as proposed, could not be advanced for confirmation.

B. DEBTOR'S PROPOSED RATES AND ITS ABILITY TO PAY ITS CURRENT CREDITORS

1. Under the proposed rates, Big Rivers would not be able to pay its current debts, in full. In fact, there would be insufficient money to pay any unsecured creditors any distribution. (Unsecured creditors under the debtor's plan of reorganization which did receive payments, if any, from Big Rivers would receive those payments merely because the RUS consented to such creditors being paid from its secured

assets.) Under the debtor's rate proposal, as explained to the Examiner, there is no ability to raise the Smelters' rates throughout the remainder of their requirements contracts [which contracts continue through 2010 (NSA) and 2011 (Alcan)]. One rate increase is forecasted for the Co-ops, which would occur on or about 2007.

2. The Examiner believes, based on a net present value analysis presented to him (which uses a discount rate of 6.37% relating to future cash flows), that rates could be proposed to the KPSC by Big Rivers which would provide both a rate reduction to all of its customers and provide payment, in full, to its current creditors.

C. DEBTOR'S BOARD OF DIRECTORS INHERENT CONFLICT WITH BOARDS OF DIRECTORS OF MEMBER DISTRIBUTION CO-OPS

1. The Big Rivers' Board of Directors is composed of twelve (12) directors. Big Rivers' four member distribution cooperatives each place 3 members on the Big Rivers' Board. From testimony by Sandra Wood, the Co-op Boards of Directors could each place two "outside" directors on the Big Rivers Board. At present, only the Green River Electric Corporation has elected an outside director to sit on the Big Rivers Board. Mrs. Wood also testified the members of the Big Rivers Board have represented the philosophy of their respective Co-ops.

2. The inherent conflict between the Big Rivers Board of Directors and the four Co-op Boards of Directors cannot be dismissed based on the argument that Congress realized that this inherent conflict existed when it established the entire

rural electric cooperative system. While Congress may have envisioned that members from the distribution cooperative boards would, in whole or in part, be elected to memberships on the board of directors of the system's generation and transmission company (in this case Big Rivers), this fact does not establish that Congress intended to approve a system which violates basic fiduciary principles. In this case, the members who serve on the Big Rivers Board do not resign their board membership on their Co-op Boards of Directors. For example, Mrs. Wood, who is Chairperson of the Big Rivers Board, is also a current member of the board of one of the cooperatives, (Green River Electric Corp.). These dual directorships create an actual conflict of interest, as will be explained.

3. The goals of the Big Rivers' Board and the four Boards of Directors of the distribution Co-ops are currently in conflict. The Board of Directors of Big Rivers (as a DIP) has a duty of loyalty to its creditors to attempt to maximize the value of Big Rivers. [This maximization of value could occur through its rate proposal, with higher rates than currently proposed (but lower rates then will exist in September, 1997) providing more value to the DIP]. In contrast, the Boards of Directors of the Co-ops want lower rates to make them more competitive in the market place. Because Board members of Big Rivers serve simultaneously on the Co-op Boards of Directors, they have different, and conflicting, duties of loyalty to their respective constituents. At the present time since the

Board of Directors of Big Rivers could have proposed rates which constituted a reduction from rates that will exist on September 1, 1997, but rates that would still be sufficiently high to pay Big Rivers' creditors, in full, a serious question arises whether the current Board of Directors at Big Rivers is discharging its duty of loyalty to Big Rivers' bankruptcy constituents. Mrs. Wood's testimony that members of the Board of Directors of Big Rivers represent the philosophy of their respective Co-ops appears to ratify this actual conflict.

4. The Co-ops' General Managers, and the Co-ops' counsel, have met twice with the Examiner. At both meetings, the Co-ops' General Managers stated strongly that they need "competitive" rates to survive in the marketplace. "Competitive" rates equates to "lower" rates. The Examiner believes that the Co-ops' General Managers are addressing the concerns of their respective Boards of Directors. Notwithstanding the General Managers' statements (which may prove to be true sometime in the future), the financial evidence at present indicates that, unlike Big Rivers, the member Co-ops are not only making money each year, but also have in excess of $116 million of "retained earnings", which the Co-ops call "patronage capital".

5. The actual conflict between Big Rivers need for high rates to pay its creditors, and the Co-ops need for lower rates to be competitive, is apparent in the manner in which Big Rivers developed its "reference case", which is the financial

basis from which it measured proposals received from interested third parties in the "resolution process". Mr. Robison testified the reference case represented Big Rivers actual rate structure approximately 1 1/2 years ago, with one exception. The one exception is that Big Rivers removed the "demand ratchet" from its reference case. It appears that the demand ratchet was inserted into Big Rivers rate structure at the KPSC when it adjudicated the 1987 rate case filed by Big Rivers. The demand ratchet is particularly offensive to the Co-ops. By failing to include the demand ratchet's affect into its reference case, Big Rivers was advancing the interests of the "Rurals" constituency of the Co-ops. (Again, this factor is consistent with Mrs. Wood's statement that the Board members of Big Rivers represent the philosophy of their Co-ops.) Also, by failing to include the "demand ratchet" into the reference case, the alleged percentage decrease in rates attributable to the "Rurals" rate will be artificially lowered, possibly by as much as 10%. Thus, when Mr. Robison testified the current rate proposal for the "Rurals" represented a 9% decrease from the "Rurals" present rates, based on the reference case, he materially understated the actual decrease in rates to the "Rurals". If the demand ratchet were included in Mr. Robison's analysis, the decrease in the "Rurals" current rate would be substantially greater than 9%, and would probably be in the range of a 20-23% decrease in rates for the Co-ops' rural customers.

6. Each of the four Co-ops in the Big Rivers system has made money in each of the last five (5) years. In contrast, Big Rivers has lost approximately $30-40 million per year over the last five (5) years. Also, Big Rivers has a negative patronage capital account in excess of $300 million, while, as stated above, the four member Co-ops have in excess of $116 million in patronage capital. Mr. John West, Vice General Manager - Finance at Big Rivers, testified that one of the four Co-ops has recently declared a patronage dividend of several million dollars.

7. Under the proposed rate structure the patronage capital account of the four Co-ops would increase by approximately $134,700,000 based on Big Rivers' projections. Under financial models created by an accounting firm hired by certain unsecured creditors in this case, the patronage capital build-up in the Co-ops under the Pacificorp deal (which adopts the debtor's proposed rate structure) is substantially greater than $134,700,000. Under Big Rivers' proposed rate structure, unless consented to by the RUS, no unsecured creditor would receive any payment under the plan.

D. DEBTOR'S CURRENT BOARD OF DIRECTORS QUESTIONABLE ABILITY TO DISCHARGE ITS FIDUCIARY DUTIES

1. Six of the current 12 members of Big Rivers' Board of Directors, including Chairperson Wood, were Board members during the period when William Thorpe was General Manager. (Thorpe was convicted of certain criminal activities while acting as General Manager of Big Rivers and awaits sentencing

in mid-December, 1996).

2. Mrs. Wood testified she believes that in 1991, Thorpe's $500,000.00 consulting contract with Jim Smith Contracting Company (which was dated June 16, 1988) was voluntarily disclosed to Morton Holbrook by Thorpe. The Examiner's investigation demonstrates this $500,000.00 consulting agreement was not disclosed voluntarily by Mr. Thorpe. The Examiner further believes common sense would tell a reasonably prudent board member this was not an agreement Mr. Thorpe would have voluntarily disclosed nearly three (3) years after the transaction occurred. This point is being made simply to demonstrate to the Court that the current Board continues its refusal to confront, and effectively deal with, difficult issues surrounding the fraud and mismanagement which existed at Big Rivers.

3. The current Board of Directors at Big Rivers has shown a disinterest in learning the extent of mismanagement, malpractice or fraudulent activities at Big Rivers. Notwithstanding the RUS requested Big Rivers to do so, Big Rivers never hired an independent consultant to investigate the matters surrounding the company's fuel procurement practices, or to investigate the Substitute Coal Agreement which Big Rivers entered into with Green River Coal Company. Big Rivers' Board of Directors has demonstrated a willingness to hire consultants for other reasons, and incur millions of dollars in fees as a result of those consultants' activities, yet, it has

failed to engage any outside entity to investigate areas involving fraud, mismanagement, malpractice or criminal activities at Big Rivers.

4. The current board appears to apply a "double-standard" relating to individuals associated with Big Rivers during Thorpe's tenure. Paul Schmitz was selected by the Big Rivers Board to be General Manager when it allowed Mr. Thorpe to resign on or about June 2, 1992. Mr. Schmitz testified that he was forced to resign in October, 1995, because the Board, and apparently Mrs. Wood, believed he was tainted by association, for he was second-in-command at Big Rivers (Vice General Manager - Finance) during the period of bribery/kick-backs in the Thorpe years. Mr. Schmitz has denied all knowledge of the bribery/kick-back scheme. The Examiner has discussed Mr. Schmitz with certain people knowledgeable about Schmitz's tenure as General Manager, and those individuals stated that they found him to be honest and industrious. The Board's decision to retire Schmitz cost Big Rivers at least $470,000.00, ($320,000.00 for a consulting agreement with Mr. Schmitz, and an increase of approximately $145,000.00 to $150,000.00 per year relating to Mr. Robison's salary [for he is now Acting General Manager and his average monthly income went from approximately $17,000.00 as Turnaround Specialist to over $29,000.00 per month (as Turnaround Specialist and Acting General Manager].) To the best of the Examiner's knowledge, the Board did not have any actual evidence of mismanagement,

fraud, or criminal activity by Mr. Schmitz. Also, if the "tainted by association" rationale is applied evenly, one could argue that all Board members who were on the Board at the time Thorpe was involved in the bribery/kick-back scheme should have also resigned. The Board's decisions relating to "how" Mr. Schmitz should be replaced (Mr. Schmitz was asked to travel to Atlanta to the law firm of Long, Aldridge and Norman under false pretenses), "why" Mr. Schmitz should be replaced (tainted by association), and the cost associated with those decisions (at least $470,000.00), place into question the current Board's ability to discharge its fiduciary duties to its bankruptcy constituencies.

5. Big Rivers has not re-opened negotiations with potential suitors after it filed its bankruptcy petition. The position of Big Rivers is that the Pacificorp deal is now known to the interested parties, and these interested parties have not presented any better deal than that offered by Pacificorp. The Examiner does not concur with that position. The Examiner believes that as DIP (a different legal entity from Big Rivers), the DIP has an affirmative duty to ensure that a better deal (than the Pacificorp proposal) for its creditors is not available.

6. The current board has failed to investigate independently whether certain actions by professionals retained by Big Rivers constituted actionable conduct by those professionals. Again, this failure by the Board to make

difficult decisions causes concern with the Examiner relating to whether the present Board can objectively discharge its fiduciary duties to ensure that all of Big Rivers' bankruptcy constituents are properly being protected.

E. DEBTOR'S STATED GOALS RELATING TO ITS RESOLUTION PROCESS HAVE SHIFTED

1. Big Rivers' goals or objectives relating to its "resolution process" have evolved over the last two (2) years. Specifically, on August 31, 1994, the announced goals were three-fold, and related to finding solutions to: (a) Big Rivers dependency on the aluminum companies; (b) long term debt; and, (c) restoration of public confidence in Big Rivers. After Big Rivers hired consultants and professionals to assist in its "resolution process" the announced goals of Big Rivers changed. On April 11, 1995, Big Rivers' announced goals were: (a) serve members with competitive rates; (b) provide low cost residential energy; (c) restore credibility in Big Rivers; and, (d) treat Big Rivers employees fairly. On June 14, 1995, when Big Rivers was soliciting requests for proposals from interested parties, it informed these interested parties of the goals and objectives which Big Rivers wanted to achieve in its "resolution process". A copy of those goals and objectives are attached hereto as Exhibit 1. It appears from a review of these announced goals and objectives that there has been a transition of goals, and the current announced goals do not appear to include all of the interests of all of Big Rivers' bankruptcy constituents.

2. While Mr. Robison testified that one of the implicit goals of Big Rivers was to maximize value of the debtor for its creditors, he conceded that he has never calculated what level of rates would be required to pay, in full, all creditors. Mr. Robison justified this failure based essentially on two factors: (1) that the Smelters would not agree to such rates and "they will do everything in their economic power to ensure that those rates are not in effect"; and, (2) "I have done calculations that indicate we couldn't support that rate level on traditional utility rate making." Mr. Robison also testified that the Banks wanted Big Rivers to make whatever deal was possible with the Smelters and then obtain the differential from the Co-ops; however, Robison believed this could not be accomplished based on a potential discrimination analysis before the KPSC.

3. The Examiner is not convinced that Mr. Robison's analysis is correct, for it appears that rate reduction and payment, in full, to creditors is possible in this case. The Examiner concurs with Mr. Robison's assessment that to pay creditors, in full, the rates to the Smelters may be higher than could be agreed to on a consensual basis; however, the KPSC has shown in the 1987 rate case filed by Big Rivers that it will adjudicate creative rate making (for instance, the variable rate adjudicated for the Smelters) to accomplish its statutory task of just and reasonable rates. Thus, Mr. Robison's failure to even calculate what rates would be needed

to pay, in full, all creditors of this estate indicates to the Examiner that the "announced" goals of Big Rivers in its "resolution process" are the actual goals the debtor is pursuing.

F. DEBTOR'S CONDUCT WITH THIS COURT CONCERNING RATE MATTERS

1. Big Rivers position concerning its rate case and this Court also concerns the Examiner. While the Examiner understands that it is solely within the province of the KPSC to establish just and reasonable utility rates (subject, of course, to this Court confirming any plan of reorganization for Big Rivers which includes that rate structure), it is also this Court's duty to ensure that the rates <u>originally</u> proposed to the KPSC demonstrate that Big Rivers, as a DIP, has discharged properly its fiduciary duties.

2. Big Rivers' actions relating to its rate case demonstrate a disregard for this Court's legitimate concern that it is properly conducting itself as DIP. The Examiner has had two discussions with counsel for the debtor relating to this Court's involvement in Big Rivers' proposed rate case filing. While reasonable minds can differ on legal technicalities, the Examiner believes that the debtor must demonstrate to this Court that it is not attempting to circumvent this Court's legitimate interest in ensuring that appropriate rates are initially proposed to the KPSC.

G. RECOMMENDATIONS OF EXAMINER

1. The issue concerning rates is clear. The Examiner

believes that the entire financial viability of the debtor's restructuring is based on what rates it charges its customers. Thus, Big Rivers' rates to its customers are the central economic issue in this case.

2. Based on the various factors set forth above, the Examiner recommends to the Court that an independent analysis be conducted to determine: (1) whether any rate case should be filed; and, (2) if a rate case should be filed the appropriate rates that the KPSC should be asked to establish.

3. These recommendations are the least invasive recommendations that the Examiner can make to the Court. For instance, the Examiner could have recommended, based on an actual conflict of interest, that a Trustee be appointed. The Examiner could also have recommended that the debtor be prohibited from ever filing its proposed rate case, based on a finding of an actual conflict of interest. At this point, the Examiner has not made either of these recommendations.

4. If the independent investigation discloses a rate case should not be filed, or if filed, materially different rates should be proposed than those currently advanced by the debtor, the Court can then enter whatever Orders it deems appropriate. If, however, the independent investigation demonstrates that, notwithstanding the actual conflict of interest which exists, the debtor's proposed rates appear to be just and reasonable, then the Court can authorize the debtor to proceed with its rate case. Also, while the rate investigation

is being undertaken, the debtor will still be in control of its day-to-day operations. At this point in the Examiner's investigation, the Examiner has found no evidence that the debtor is not properly conducting its day-to-day business affairs. (If a Trustee were appointed the Trustee would be responsible for the day-to-day operations of the debtor.)

5. If the Court agrees with the Examiner's Recommendations, this is not a task that can be quickly achieved. Mr. Robison, who has been advising the debtor for an extended period of time, testified the rate case was an "extraordinary complex process. I think there's 27 specific activities involving thirty or forty people all having to come together in a filing that is consistent with the regulations of the Public Service Commission." Based on Mr. Robison's assessment of the complexities of this matter, the Examiner believes it will, in all likelihood, require eight (8) months to one (1) year before the independent analysis could be completed and a report prepared for this Court.

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Examiner

Goal and Objectives

- The surviving entity must meet the wholesale power and transmission requirements of the distribution cooperatives at competitive rates.
- The surviving entity must preserve the historic mission of Big Rivers to reliably serve rural residential customers with electricity at the lowest reasonable cost.
- The surviving entity must be able to serve industrial and commercial users through the distribution cooperatives at competitive rates and facilitate rural, commercial and industrial economic development in Big Rivers' service area.
- The surviving entity must simultaneously eliminate the cloud over Big Rivers' financial viability, expand and diversify its customer base and restore long term financial credibility with its creditors.
- The surviving entity must be able to compete effectively with other potential power suppliers of electricity.
- The surviving entity must restore confidence in Big Rivers' customer base.
- The surviving entity must deal fairly with Big Rivers' current employees.
- The surviving supplier must be competitive with substitute fuels and surrounding utilities.
- The surviving supplier must provide long term rate stability.
- The surviving entity or the Members must retain direct or indirect control of Big Rivers' transmission assets.
- The surviving entity should enable the Members to retain the aluminum load in the near term and facilitate industrial load diversification through competitive rates.
- Eliminate the demand ratchet in Big Rivers' wholesale rate to the Members.

Exhibit 1

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
FOR INFORMATION TO JOINT APPLICANTS
PSC CASE NO. 2007-00455
February 14, 2008

Item 146) The Attorney General made the following request after his Initial Data Requests were served: "In our review it appears that "Exhibit A" to the Smelter retail agreements contains a template/pro forma calculation of charges under the agreement (extending to 10 pages). This appears to be an Excel spreadsheet. Please provide a copy of this spreadsheet with formulas and data sources left intact."

Response) See the attached CD, containing:

1. Century Retail;
2. Century Wholesale;
3. Alcan Retail;
4. Alcan Wholesale.

Witness) Robert S. Mudge