Main Case File

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
1 of 4

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

William Steven Seelye

STATE OF Kentucky)
COUNTY OF Jefferson)

SUBSCRIBED AND SWORN TO before me by William Steven Seelye on this the 13th day of February, 2008.

Notary Public, Victoria B. Harper
My Commission Expires Sept 20, 2010

RECEIVED

FEB 14 2008

PUBLIC SERVICE COMMISSION

VERIFICATION

I verify, state, and affirm that the foregoing testimony is true and correct to the best of my knowledge and belief.

Robert S. Mudge

District of Columbia)
City of Washington)

SUBSCRIBED AND SWORN TO before me by Robert S. Mudge on this the 13 day of February, 2008.

Notary Public, District of Columbia
My Commission Expires: ____________

Notary Public District of Columbia
CHARLES HELLER
My Commission Expires: Sept 30, 2008

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

Mark W. Glotfelty

STATE OF NEW YORK
COUNTY OF NEW YORK

SUBSCRIBED AND SWORN TO before me by Mark W. Glotfelty on this the 12th day of February, 2008.

Patricia A. Crawley
Notary Public, ______________ PATRICIA A. CRAWLEY
My Commission Expires ______ Notary Public, State of New York
No. 31-4817132
Qualified in New York County
Commission Expires Jan. 31, 2011

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

Burns Mercer

COMMONWEALTH OF KENTUCKY)
COUNTY OF Meade)

SUBSCRIBED AND SWORN TO before me by Burns Mercer on this the 12th day of February, 2008.

Notary Public, Ky. State at Large
My Commission Expires 3-18-08

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

Michael H. Core

STATE OF Kentucky)
COUNTY OF Henderson)

SUBSCRIBED AND SWORN TO before me by Michael H. Core on this the 12th day of February, 2008.

Paula Mitchell
Notary Public, Ky. State at Large
My Commission Expires 1-12-09

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

David A. Spainhoward

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by David A. Spainhoward on this the 12th day of February, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-09

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

C William Blackburn

C. William Blackburn

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by C. William Blackburn on this the 12th day of February, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-09

VERIFICATION

I verify, state, and affirm that the foregoing responses for which I am listed as a witness are true and correct to the best of my knowledge and belief.

Mark A. Bailey

Mark A. Bailey

COMMONWEALTH OF KENTUCKY)
COUNTY OF HENDERSON)

SUBSCRIBED AND SWORN TO before me by Mark A. Bailey on this the 12th day of February, 2008.

Paula Mitchell

Notary Public, Ky. State at Large
My Commission Expires 1-12-09

Item 1) State each material fact which prevents Big Rivers from electing to continue its present mode of operation under the existing Lease Agreement.

Response) There are no material facts that keep Big Rivers from continuing its present mode of operations under the existing Lease Agreement or existing Purchase Power Agreement, other than its contractual obligations under the Termination Agreement. The decision made by Big Rivers to pursue the Unwind Transaction was rather one of balancing the reasons for staying in the current arrangement against those for proceeding with the Unwind.

As discussed below in the response to the Attorney General's Initial Request, Item 43, those reasons include the financial strictures of the current arrangement versus the financial flexibility Big Rivers will have under the Unwind Transaction. Currently, Big Rivers has no way to adequately fund significant new capital obligations for litigation liability, environmental assessments, capital additions for load growth, or unexpectedly large obligations it may face at Lease end. Moreover, the current arrangement has seen its share of continuing disputes between E.ON and Big Rivers, and E.ON clearly is eager to sever ties. Facing a clearly dissatisfied partner in E.ON for the next sixteen years—or two Smelters desperate to find a low-cost source of power—is not pleasant to contemplate. Both the direct and indirect employment benefits derived from the Smelters and the opportunity for further economic development in Western Kentucky under the Unwind Transaction militate against the status quo. Finally, Big Rivers is committed to being a long-term power supplier for Western Kentucky, and the Lease Agreement and Power Purchase Agreement offer only a short-term fix rather than a lasting solution.

Witness) Michael H. Core

Item 2) State each material fact which prevents Big Rivers from electing to continue its present mode of operation under the existing Power Purchase Agreement.

Response) See Big Rivers' Response to the Attorney General's Initial Request, Item 1.

Witness) Michael H. Core

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
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Item 3) Provide the most recent comparison of expected future cash flows to Big Rivers under continuation of the existing Lease Agreement/Power Purchase Agreement versus expected future cash flows as modeled (Exhibit 8) for the proposed Unwind/Lease Agreement Termination transactions, performed by or for Big Rivers

i. Please explain why such a comparison was not performed; and,
ii. Provide the requested comparison.

Response) Please see comparison of expected future cash flows to Big Rivers under continuation of the existing Lease Agreement/Purchase Power Agreement versus expected future cash flows as modeled (Exhibit 8) for the proposed Unwind/Lease agreement Termination Transaction.

Witness) C. William Blackburn

Item 4) It is stated that Big Rivers "exists for the principal purpose of providing the wholesale electricity requirements of its three distribution cooperative members", (emphasis added).

a. State each and every other purpose for which Big Rivers exists.

b. Describe and discuss the nature of each such "other purpose" identified in a.

Response) KRS Chapter 279 states the purposes for which electric cooperatives may be organized:

> 279.020 Who may incorporate.
> Any three (3) or more individuals, partnerships, associations or private corporations a majority of whom are citizens of Kentucky, may by executing, filing, and recording articles of incorporation as provided in KRS 279.030 and 279.040 organize to conduct a nonprofit cooperative corporation for the:
> (1) Primary purpose of generating, purchasing, selling, transmitting, or distributing electric energy to any individual or entity, and providing any good or service related to generating, purchasing, selling, transmitting, or distributing electric energy to any individual or entity; and
> (2) If the cooperative desires, for the secondary purpose of engaging in any other lawful business or activity, provided that any nonregulated business or activity is conducted through an affiliate except for any business or activity which does not involve the sale of a product that is conducted pursuant to a contract with a federal military installation or a contract for administrative services which does not involve the sale of a product requested by a local, state, or federal government.

Article II of the Big Rivers Articles of Incorporation sets forth the specific purposes for which Big Rivers was organized:

ARTICLE II

The purpose or purposes for which the corporation is formed are to promote and encourage the fullest possible use of electric energy in the Commonwealth of Kentucky, by making electric energy available by production, transmission, distribution, or by otherwise securing the same for inhabitants of and persons, including natural persons, firms, associations, corporations, business trusts, partnerships and bodies politic and corporate, in rural areas of the Commonwealth of Kentucky, at the lowest cost consistent with sound business methods and prudent management of the business of the corporation and also by making available to the said inhabitants and persons, including natural persons, firms, associations, corporations, business trusts, partnerships and bodies politic and corporate, electrical devices, equipment, wiring, appliances, fixtures, supplies and machinery (including any fixtures or property, or both, which may by its use be conducive to a more complete use of electricity or electric energy) operated by electricity or electric energy, and accounting services, forms and supplies, bargaining services, business counsel and advice, engineering services, supervisory services, investment counsel, general purchasing services of all kinds, and any other services that are requested or deemed advisable or desirable in the conduct of the business of the corporation or in the business of any natural persons, firms, associations, corporations, business trusts, partnerships and bodies politic and corporate, in rural areas of the Commonwealth of Kentucky. In addition, the purpose or purposes for which the corporation is formed are, without limiting the generality of the foregoing:

(a) to generate, manufacture, purchase, transport, acquire and accumulate electric energy for its members and non-members to the extent permitted by the Act under which the Corporation is formed and to transmit, distribute, furnish, sell, and dispose of such electric energy to its members and non-members to the extent permitted by the Act under which the Corporation is formed, and to construct, erect, purchase, lease as lessee and in any manner acquire, own, hold, maintain, operate, sell dispose of, lease as lessor, exchange and mortgage plants, buildings, works, machinery, supplies, apparatus, equipment and electric transmission and distribution lines or systems necessary, convenient or useful for carrying out and accomplishing any or all of the foregoing purposes;

(b) to acquire, own, hold, use, exercise and, to the extent permitted by law, to sell, mortgage, pledge, hypothecate and in any manner dispose of franchises, rights, privileges, licenses, rights of way and easements necessary, useful or appropriate to accomplish any or all of the purposes of the Corporation;

(c) to purchase, receive, lease as lessee, or in any other manner acquire, own, hold, maintain, use, convey, sell, lease as lessor, exchange, mortgage, pledge or otherwise dispose of any and all real and personal property or any interest therein necessary, useful or appropriate to enable the Corporation to accomplish any or all of its purposes;

(d) to assist its members to wire their premises and install therein electrical and plumbing appliances, fixtures, machinery, supplies, apparatus and equipment of any and all kinds and character (including, without limiting the generality of the foregoing, such as are applicable to water supply and sewage disposal) and, in connection therewith and for such purposes, to purchase, acquire, lease, sell, distribute, install and repair electrical and plumbing appliances, fixtures, machinery, supplies, apparatus and equipment of any and all kinds and character (including, without limiting the generality of the foregoing, such as are applicable to water supply and sewage disposal) and to receive, acquire, endorse, pledge, guarantee, hypothecate, transfer or otherwise dispose of notes and other evidences of indebtedness and all security therefor;

(e) to borrow money, to make and issue bonds, notes and other evidences of indebtedness, secured or unsecured, for monies borrowed or in payment for property acquired, or for any of the other objects or purposes of the Corporation; to secure the payment of such bonds, notes or other evidences of indebtedness by mortgage or mortgages, or deed or deeds of trust upon, or by the pledge of or other lien upon, any or all of the property, rights, privileges or permits of the Corporation, wheresoever situated, acquired or to be acquired;

(f) to do and perform, either for itself or its members, any and all acts and things, and to have and exercise any and all powers, as may be necessary or convenient to accomplish any or all of the foregoing purposes or as may be permitted by the Act under which the Corporation is formed, and to exercise any of its power anywhere.

Witness) Michael H. Core

Item 5) Does Big Rivers have committed financing as represented for example by "Commitment Letters" from lenders for the new debt financing to finance the Unwind Transaction?

a. If so, please provide the Commitment Letters and most current draft loan agreements and documentation.

b. If not, please state when committed debt financing will be sought by Big Rivers.

Response) No term sheets have been agreed to and no firm commitments have been given. However, discussions are on-going. An alternative long-term financing scenario Big Rivers is exploring with the RUS is applying $200 million to the New RUS Note upon the Unwind closing, plus on-going quarterly debt service payments equal to the representative portion of the Unwind level debt service, which would allow Big Rivers not to exceed the Allowed Balance amount shown on the RUS Maximum Debt Balance Schedule for several years. By the end of that time, Big Rivers expects the refinancing to occur. Approval of the RUS is required to allow for the scenario discussed above, and for amending the existing notes, including the RUS ARVP Note.

Witness) C. William Blackburn

Item 6) Provide documents which show most current projected load growth over the next five years for Big Rivers' member cooperatives (Kenergy, Corp., Jackson Purchase Energy Corporation, and Meade County Rural Electric Cooperative), including load growth for smelters separately.

Response) See table attached.

Witness) C. William Blackburn

BIG RIVERS ELECTRIC CORPORATION

2007 LONG-TERM LOAD FORECAST - BASE CASE
TOTAL NATIVE ENERGY REQUIREMENTS
PLUS SMELTERS & FIRM OFF-SYSTEM CONTRACTS

Year	Native Energy Sales (MWh)	Smelters Energy Sales (MWh)	Native + Smelters (MWh)	Off-System Firm Sales (MWh)	Total Sales (MWh)
2007	3,294,909	7,322,055	10,616,964		10,616,964
2008	3,375,398	7,335,682	10,711,080		10,711,080
2009	3,430,733	7,335,682	10,766,414		10,766,414
2010	3,477,341	7,335,682	10,813,022		10,813,022
2011	3,530,346	7,335,682	10,866,028		10,866,028
2012	3,579,072	7,335,682	10,914,754		10,914,754
2013	3,634,373	7,335,682	10,970,054		10,970,054
2014	3,684,296	7,335,682	11,019,978		11,019,978
2015	3,741,063	7,335,682	11,076,745		11,076,745
2016	3,793,225	7,335,682	11,128,906		11,128,906
2017	3,851,997	7,335,682	11,187,679		11,187,679
2018	3,906,298	7,335,682	11,241,979		11,241,979
2019	3,966,110	7,335,682	11,301,792		11,301,792
2020	4,021,927	7,335,682	11,357,609		11,357,609
2021	4,083,955	7,335,682	11,419,637		11,419,637

Item 7) Please provide information concerning executive succession plans along with a copy of any executive retirement policies of the company. If no such plan or policies exist, please state the reason(s) why.

Response) There is no executive succession policy or any executive retirement policy of the company. As to retirement, all salaried employees have the same retirement plan, 401K, and retiree medical benefits. The retirement plan for all new hires after January 1, 2008 will become a defined contribution plan. Existing employees will remain in a defined benefit plan.

As to a succession procedure for the CEO, my filed testimony states, "In mid 2006 I informed the Big Rivers Board that the Unwind Transaction, if completed and approved, could likely be implemented near the time period that I had been contemplating retirement. In order to ensure a smooth succession plan, I asked the Board to give thought to bringing a successor to my position so he or she could work with me and the Big Rivers staff during the completion of the Unwind Transaction and the transition to Big Rivers again becoming an operating generation and transmission cooperative. In late 2006 the Big Rivers' Board hired Mark A. Bailey as my successor upon my retirement. Mark is the former President and CEO of Kenergy Corp. and joined the Big Rivers executive team on June 1 of this year as Executive Vice President of Big Rivers."

Also, at the end of my filed testimony, I stated, "After the closing of the Unwind Transaction, Mr. Bailey will become the Big Rivers President and CEO, and I will phase into retirement."

Over the last decade Big Rivers' executive management staff has been small enough that planning for succession has been handled on an informal, individual basis. After the Unwind closing, Big Rivers will reexamine whether that system is appropriate for the larger entity.

BIG RIVERS ELECTRIC CORPORATION'S
RESPONSE TO THE ATTORNEY GENERAL'S INITIAL REQUEST
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Witness) Michael H. Core

Item 8) Please provide details as to the positions of the current executives of the company during the company's bankruptcy. Will the same executives that presided over the company during the bankruptcy operate the company after the unwind transaction?

Response) Michael Core was hired by Big Rivers as president and CEO a few days before Big Rivers filed its petition for reorganization in September of 1996, and his hiring was approved by the bankruptcy court in December of 1996. Michael Core will continue in that role until his retirement post-Unwind closing. Travis Housley was Vice General Manager of System Operations prior to the filing of the petition for reorganization. He is currently the Vice President of Special Projects, and will retire following the Unwind closing upon completion of the Unwind-related projects for which he is responsible.

The individuals from the executive team described in exhibit MAB-2, which supplements Mark Bailey's filed testimony, held the following positions during Big Rivers' bankruptcy proceedings:

C. William Blackburn- Manager of General Accounting
David Spainhoward- Coordinator of Regulatory and Contract Affairs
Mark Hite- Manager of Financial Services
James Haner- Manager of Corporate Services, Insurance and Loss Control
David Crockett- Manager of Engineering
Bob Berry- Superintendent of Maintenance, Green Station

With the exception of Travis Housley, no person who held an executive position (vice president or higher) prior to Big Rivers' bankruptcy is currently employed by Big Rivers, or expected to be employed by Big Rivers for any significant period of time post-Unwind closing.

Witness) Michael H. Core

Item 9) Please provide information concerning the unwind transactions' effect on the company's executive retirement plans. Are there any material benefits to the executives which result from the unwind transaction?

Response) Big Rivers has no "executive retirement plans." There are no material benefits to executives as a result of the Unwind Transaction. There is no vesting of any benefit to any executive, nor augmentation of any executive's retirement benefits, which is contingent on a successful closing of the unwind.

Witness) Michael H. Core

Item 10) Provide documents which show Big Rivers' sales on the regional wholesale power market for the past three years.

Response) See PSC Item 35(b).

Witness) C. William Blackburn

Item 11) In addition to Exhibit 37, provide the complete CPA audit report for Big Rivers, for 2004 and 2007 when completed.

Response) A copy of the Big Rivers' 2004 Independent Auditors' Report is attached. The 2007 Independent Auditor's Report is currently anticipated to be completed March 21, 2008 and will be provided at that time.

Witness) C. William Blackburn

Deloitte.

Big Rivers Electric Corporation

Financial Statements as of December 31, 2004 and 2003 and for Each of the Three Years in the Period Ended December 31, 2004 and Independent Auditors' Report

Deloitte

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INDEPENDENT AUDITORS' REPORT

Board of Directors
Big Rivers Electric Corporation

We have audited the accompanying balance sheets of Big Rivers Electric Corporation (the "Company") as of December 31, 2004 and 2003, and the related statements of operations, equities (deficit) and cash flows for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards*, issued by the Comptroller General of the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

In accordance with *Government Auditing Standards*, we have also issued a report dated March 2, 2005, on our consideration of the Company's internal control over financial reporting and our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* and should be read in conjunction with this report in considering the results of our audit.

Deloitte & Touche LLP

Indianapolis, Indiana
March 2, 2005

BIG RIVERS ELECTRIC CORPORATION

BALANCE SHEETS
DECEMBER 31, 2004 AND 2003
(Dollars in thousands)

ASSETS	**2004**	**2003**
UTILITY PLANT—Net	$ 940,649	$ 946,958
RESTRICTED INVESTMENTS UNDER LONG-TERM LEASE	174,695	168,859
OTHER DEPOSITS AND INVESTMENTS—At cost	3,246	2,969
CURRENT ASSETS:		
Cash and cash equivalents	54,891	15,802
Accounts receivable	15,609	15,348
Materials and supplies inventory	555	588
Prepaid expenses	348	574
Total current assets	71,403	32,312
DEFERRED CHARGES AND OTHER	30,647	31,758
TOTAL	$ 1,220,640	$ 1,182,856
EQUITIES (DEFICIT) AND LIABILITIES		
CAPITALIZATION:		
Equities (deficit)	$ (278,256)	$ (300,281)
Long-term debt	1,079,688	1,053,598
Obligations related to long-term lease	164,704	158,597
Other long-term obligations	437	789
Total capitalization	966,573	912,703
CURRENT LIABILITIES:		
Current maturities of long-term obligations	781	747
Voluntary prepayment of long-term debt	-	8,404
Notes payable	-	10,000
Purchased power payable	9,204	8,654
Accounts payable	2,910	2,997
Accrued expenses	1,638	1,713
Accrued interest	8,004	6,470
Total current liabilities	22,537	38,985
DEFERRED CREDITS AND OTHER:		
Deferred lease revenue	26,090	30,357
Deferred gain on sale-leaseback	62,118	64,941
Residual value payments obligation	138,693	131,130
Other	4,629	4,740
Total deferred credits and other	231,530	231,168
COMMITMENTS AND CONTINGENCIES		
TOTAL	$ 1,220,640	$ 1,182,856

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF OPERATIONS
YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002
(Dollars in thousands)

	2004	2003	2002
POWER CONTRACTS REVENUE	$ 175,777	$ 162,432	$ 146,548
LEASE REVENUE	56,753	53,040	51,094
Total operating revenue	232,530	215,472	197,642
OPERATING EXPENSES—Operations:			
Power purchased and interchanged	106,099	96,577	85,722
Transmission and other	18,674	17,383	14,669
MAINTENANCE	2,597	2,617	3,100
DEPRECIATION	29,732	28,257	27,745
Total operating expenses	157,102	144,834	131,236
ELECTRIC OPERATING MARGINS	75,428	70,638	66,406
INTEREST EXPENSE AND OTHER:			
Interest	56,923	57,645	59,801
Interest on obligations related to long-term lease	8,725	8,355	8,003
Other—net	158	136	147
Total interest expense and other	65,806	66,136	67,951
OPERATING MARGIN	9,622	4,502	(1,545)
NON-OPERATING MARGIN:			
Interest income on restricted investments under long-term lease	11,278	10,894	10,527
Interest income and other	1,125	2,953	1,073
Total non-operating margin	12,403	13,847	11,600
NET MARGIN	$ 22,025	$ 18,349	$ 10,055

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF EQUITIES (DEFICIT)
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002
(Dollars in thousands)

	Total Equities (Deficit)	Accumulated Deficit	Other Equities: Donated Capital and Memberships	Other Equities: Consumers' Contributions to Debt Service
BALANCE—January 1, 2002	$ (328,685)	$ (333,130)	$764	$ 3,681
Net margin	10,055	10,055	-	-
Accumulated other comprehensive loss	(383)	(383)	-	-
BALANCE—December 31, 2002	(319,013)	(323,458)	764	3,681
Net margin	18,349	18,349	-	-
Accumulated other comprehensive income	383	383	-	-
BALANCE—December 31, 2003	(300,281)	(304,726)	764	3,681
Net margin	22,025	22,025	-	-
BALANCE—December 31, 2004	$ (278,256)	$ (282,701)	$764	$ 3,681

See notes to financial statements.

BIG RIVERS ELECTRIC CORPORATION

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2004, 2003 AND 2002
(Dollars in thousands)

	2004	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net margin	$ 22,025	$ 18,349	$ 10,055
Adjustments to reconcile net margin to net cash provided by operating activities:			
Depreciation and amortization	32,625	30,872	30,397
Increase in restricted investments under long-term lease	(5,836)	(5,605)	(5,240)
Amortization of deferred gain on sale-leaseback	(2,823)	(2,785)	(2,744)
Deferred lease revenue	(4,267)	(3,059)	6,141
Residual value payments obligation	(5,077)	(1,726)	329
Increase in RUS ARVP Note	4,807	4,546	4,298
Increase in New RUS Promissory Note	21,849	-	-
Increase in obligations under long-term lease	6,107	5,850	5,461
Changes in certain assets and liabilities:			
Accounts receivable	(261)	(628)	4,860
Materials and supplies inventory	33	(14)	(24)
Prepaid expenses	226	(398)	295
Deferred charges	(368)	1,602	(2,604)
Purchased power payable	550	1,016	178
Accounts payable	(87)	(4,633)	2,522
Accrued expenses	1,459	(6,177)	(531)
Other—net	(104)	3,107	(1,307)
Net cash provided by operating activities	70,858	40,317	52,086
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures—net	(12,203)	(21,397)	(21,700)
Other deposits and investments	(277)	5,733	(1,890)
Net cash used in investing activities	(12,480)	(15,664)	(23,590)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Principal payments on long-term obligations	(9,289)	(38,912)	(67,644)
Principal payments on short-term notes payable	(10,000)	(7,500)	-
Proceeds from short-term notes payable	-	17,500	-
Net cash used in financing activities	(19,289)	(28,912)	(67,644)
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	39,089	(4,259)	(39,148)
CASH AND CASH EQUIVALENTS—Beginning of year	15,802	20,061	59,209
CASH AND CASH EQUIVALENTS—End of year	$ 54,891	$ 15,802	$ 20,061
SUPPLEMENTAL CASH FLOW INFORMATION:			
Cash paid for interest	$ 28,485	$ 57,103	$ 55,634
Cash paid for taxes	$ 270	$ 400	$ -

See notes to financial statements.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General Information—Big Rivers Electric Corporation ("Big Rivers" or the "Company"), an electric generation and transmission cooperative, supplies wholesale power to its three member distribution cooperatives (Kenergy Corp, Jackson Purchase Energy Corporation and Meade County RECC) under all requirements contracts, excluding the power needs of two large aluminum smelters (the "Aluminum Smelters"), sells surplus power under separate contracts to Kenergy Corp for a portion of the Aluminum Smelters load, and markets power to non-member utilities and power marketers. The members provide electric power and energy to industrial, residential and commercial customers located in portions of 22 western Kentucky counties. The wholesale power contracts with the members extend to January 1, 2023. Rates to Big Rivers' members are established by the Kentucky Public Service Commission ("KPSC") and are subject to approval by the Rural Utilities Service ("RUS"). The financial statements of Big Rivers include the provisions of Statement of Financial Accounting Standards ("SFAS") No. 71, *Accounting for the Effects of Certain Types of Regulation,* which was adopted by the Company in 2003, and gives recognition to the ratemaking and accounting practices of these agencies.

In 1999, Big Rivers Leasing Corporation ("BRLC") was formed as a wholly-owned subsidiary of Big Rivers. BRLC's principal assets are the restricted investments acquired in connection with the 2000 sale-leaseback transaction discussed in Note 4.

Principles of Consolidation—The financial statements of Big Rivers include the accounts of Big Rivers and its wholly owned subsidiary, BRLC. All significant intercompany transactions have been eliminated.

Use of Estimates—The preparation of the financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and disclosure of contingent assets and liabilities. The estimates and assumptions used in the accompanying financial statements are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

System of Accounts—Big Rivers' accrual basis accounting policies follow the Uniform System of Accounts as prescribed by the RUS Bulletin 1767B-1, as adopted by the KPSC. The regulatory agencies retain authority and periodically issue orders on various accounting and ratemaking matters.

Revenue Recognition—Revenues generated from the Company's wholesale power contracts are based on month-end meter readings and are recognized as earned. In accordance with SFAS No. 13, *Accounting for Leases*, Big Rivers' revenue from the Lease Agreement is recognized on a straight-line basis over the term of the lease. The major components of this lease revenue include the annual lease payments and the Monthly Margin Payments (described in Note 2).

In conjunction with the Lease Agreement, Big Rivers expects to realize the following minimum lease revenue for the years ending December 31:

Year	Amount
2005	$ 52,332
2006	52,332
2007	52,332
2008	52,332
2009	52,332
Thereafter	514,534
	$776,194

Utility Plant and Depreciation—Utility plant is recorded at original cost, which includes the cost of contracted services, materials, labor, overhead and an allowance for borrowed funds used during construction. Replacements of depreciable property units, except minor replacements, are charged to utility plant.

Allowance for borrowed funds used during construction is included on projects with an estimated total cost of $250 or more before consideration of such allowance. The interest capitalized is determined by applying the effective rate of Big Rivers' weighted-average debt to the accumulated expenditures for qualifying projects included in construction in progress.

In accordance with the terms of the Lease Agreement, the Company generally records capital additions for Incremental Capital Costs and Non-incremental Capital Costs expenditures funded by LG&E Energy Corporation as utility plant to which the Company maintains title. A corresponding obligation to LG&E Energy Corporation is recorded for the estimated portion of these additions attributable to the Residual Value Payments (see Note 2). A portion of this obligation is amortized to lease revenue over the useful life of those assets during the remaining lease term. For the years ended December 31, 2004 and 2003, the Company has recorded $12,641and $35,412, respectively, for such additions in utility plant. The Company has recorded $5,077, $1,726, and $(329), in 2004, 2003, and 2002, respectively, as related lease revenue (expense) in the accompanying financial statements.

In accordance with the Lease Agreement, and in addition to the capital costs funded by LG&E Energy Corporation (see Note 2) that are recorded by the Company as utility plant and lease revenue, LG&E Energy Corporation also incurs certain Non-Incremental Capital Costs and Major Capital Improvements (as defined in the Lease Agreement) for which they forego a Residual Value Payment by Big Rivers upon lease termination. Such amounts are not recorded as utility plant or lease revenue by the Company. At December 31, 2004, the cumulative Non-Incremental Capital Costs amounted to $6,601 (unaudited). LG&E Energy Corporation is also in the process of constructing a scrubber (Major Capital Improvement) on Big Rivers' Coleman plant. This scrubber is estimated to be placed into service July 2006 at a cost of $98,000 (unaudited), none of which is expected to be recorded as utility plant or lease revenue.

Depreciation of utility plant in service is recorded using the straight-line method over the estimated remaining service lives, as approved by the RUS and KPSC. The annual composite depreciation rates used to compute depreciation expense were as follows:

Electric plant-leased	1.60 - 2.47%
Transmission plant	1.76 - 3.24%
General plant	1.11 - 5.62%

For 2004, 2003 and 2002, the average composite depreciation rates were 1.86%, 1.83%, and 1.85%, respectively. At the time plant is disposed of, the original cost plus cost of removal less salvage value of such plant is charged to accumulated depreciation, as required by the RUS.

Impairment Review of Long-Lived Assets—Long-lived assets are reviewed as facts and circumstances indicate that the carrying amount may be impaired. This review is performed in accordance with SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets*". SFAS 144 establishes one accounting model for all impaired long-lived assets and long-lived assets to be disposed of by sale or otherwise. SFAS 144 requires the evaluation for impairment involve the comparison of an asset's carrying value to the estimated future cash flows the asset is expected to generate over its remaining life. If this evaluation were to conclude that the carrying value of the asset is impaired, an impairment charge would be recorded based on the difference between the asset's carrying amount and its fair value (less costs to sell for assets to be disposed of by sale) as a charge to operations or discontinued operations.

Restricted Investments—Investments are restricted under contractual provisions related to the sale-leaseback transaction discussed in Note 4. These investments have been classified as held-to-maturity and are carried at amortized cost.

Cash and Cash Equivalents—Big Rivers considers all short-term, highly-liquid investments with original maturities of three months or less to be cash equivalents.

Income Taxes—As a taxable cooperative, Big Rivers is entitled to exclude the amount of patronage allocations to members from taxable income. Income and expenses related to non-member operations are taxable to Big Rivers. Big Rivers and BRLC file a consolidated Federal income tax return and Big Rivers files a separate Kentucky income tax return.

Patronage Capital—As provided in the bylaws, Big Rivers accounts for each year's patronage-sourced income, both operating and non-operating, on a patronage basis. Notwithstanding any other provision of the bylaws, the amount to be allocated as patronage capital for a given year shall be not less than the greater of regular taxable patronage-sourced income or alternative minimum taxable patronage-sourced income. During 2004 and 2003, the Company made a patronage allocation of $-0- and $18,937, respectively, to its three member distribution cooperatives based on alternative minimum taxable patronage-sourced income in accordance with its bylaws. The Company anticipates no patronage allocation to its members in 2005 based on such calculations for tax year 2004.

Derivatives—Management has reviewed the requirements of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended and interpreted, and has determined that all contracts meeting the definition of a derivative also qualify for the normal purchases and sales exception under SFAS No. 133 and, therefore, are not required to be recognized at fair value in the financial statements.

Reclassifications—Certain amounts in the prior years' financial statements have been reclassified to conform with current year presentation.

New Accounting Pronouncements—

In December 2003, FASB issued SFAS No. 132 (revised 2003), *Employers' Disclosures about Pensions and Other Postretirement Benefits*", to improve financial statement disclosures for defined benefit plans.

The change replaces existing FASB disclosure requirements for pensions and postretirement plans. The guidance is effective for fiscal years ending after June 15, 2004. The adoption did not impact the Company's results of operations or financial condition. The incremental disclosure requirements are included in these financial statements in Notes 9 and 10.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity*. SFAS No. 150 establishes standards for how an issuer classifies and measures three classes of freestanding financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within its scope as a liability (or an asset in some circumstances). SFAS No. 150 is effective for mandatorily redeemable financial instruments of non-public entities for the first fiscal period beginning after December 15, 2004. Management does not expect the adoption of SFAS No. 150 to have a significant impact on its financial position or results of operations.

2. LG&E LEASE AGREEMENT

On July 15, 1998 ("Effective Date"), a lease was consummated ("Lease Agreement"), whereby Big Rivers leased its generating facilities to Western Kentucky Energy Corporation ("WKEC"), a wholly owned subsidiary of LG&E Energy Corporation ("LEC"). Pursuant to the Lease Agreement, WKEC operates the generating facilities and maintains title to all energy produced. Throughout the lease term, in order for Big Rivers to fulfill its obligation to supply power to its members, the Company purchases substantially all of its power requirements from LG&E Energy Marketing Corporation ("LEM"), a wholly owned subsidiary of LEC, pursuant to a power purchase agreement.

Big Rivers continues to operate its transmission facilities and charges LEM tariff rates for delivery of the energy produced by WKEC and consumed by LEM's customers. The significant terms of the Lease Agreement are as follows:

I. WKEC leases and operates Big Rivers' generation facilities through 2023.

II. Big Rivers retains ownership of the generation facilities both during and at the end of the lease term.

III. WKEC pays Big Rivers an annual lease payment of $30,965 over the lease term, subject to certain adjustments.

IV. On the Effective Date, Big Rivers received $69,100 representing certain closing payments and the first two years of the annual lease payments. In accordance with SFAS No. 13, *Accounting for Leases*, the Company amortizes these payments to revenue on a straight-line basis over the life of the lease.

V. Big Rivers continues to provide power for its members, excluding the member loads serving the Aluminum Smelters, through its power purchase agreements with LEM and the Southeastern Power Administration, based on a pre-determined maximum capacity. When economically feasible, the Company also obtains the power necessary to supply its member loads, excluding the Aluminum Smelters, in the open market. Kenergy's retail service for the Aluminum Smelters is served by LEM and other third-party providers that may include Big Rivers. To the extent the power purchased from LEM does not reach pre-determined minimums, the Company is required to pay certain penalties. Also, to the extent additional power is available to Big Rivers under the LEM contract, Big Rivers may sell to non-members.

VI. LEM will reimburse Big Rivers an additional $109,831 for the margins expected from the Aluminum Smelters through 2011, being defined as the net cash flows that Big Rivers anticipated receiving if the Company had continued to serve the Aluminum Smelters' load, as filed in the Rate Hearing, (the "Monthly Margin Payments").

VII. WKEC is responsible for the operating costs of the generation facilities; however, Big Rivers is partially responsible for ordinary capital expenditures ("Non-incremental Capital Costs") for the generation facilities over the term of the Lease Agreement, generally up to predetermined annual amounts. This cumulative amount is not expected to exceed $148,000 over the entire 25½ year Lease Agreement. At the end of the lease term, Big Rivers is obligated to fund a "Residual Value Payment" to LEC for such capital additions during the lease, currently estimated to be $125,880 (see Note 1). Adjustments to the Residual Value Payment will be made based upon actual capital expenditures. Additionally, WKEC will make required capital improvements to the facilities to comply with a new law or a change to existing law ("Incremental Capital Costs") over the lease life (the Company is partially responsible for such costs: 20% through 2010) and the Company will be required to submit another Residual Value Payment to LEC for the undepreciated value of WKEC's 80% share of these costs, at the end of the lease, currently estimated to be $15,550. The Company will have title to these assets during the lease and upon lease termination.

VIII. Big Rivers entered into a note payable with LEM for $19,676 (the "LEM Settlement Note") to be repaid over the term of the Lease Agreement, which bears interest at 8% per annum, in consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements. The Company recorded this obligation as a component of deferred charges with the related payable recorded as long-term debt in the accompanying balance sheets. This deferred charge is being amortized on a straight-line basis over the lease term.

IX. On the Effective Date, Big Rivers paid a non-refundable marketing payment of $5,933 to LEM, which has been recorded as a component of deferred charges. This amount is being amortized on a straight-line basis over the lease term.

X. During the lease term, Big Rivers will be entitled to certain "billing credits" against amounts the Company owes LEM under the power purchase agreement. Each month during the first 55 months of the lease term, Big Rivers received a credit of $89. For the year 2011, Big Rivers will receive a credit of $2,611 and for the years 2012 through 2023, the Company will receive a credit of $4,111 annually.

In accordance with the power purchase agreement with LEM, the Company is allowed to purchase power in the open market rather than from LEM, incurring penalties when the power purchased from LEM does not meet certain minimum levels, and to sell excess power (power not needed to supply its jurisdictional load) in the open market (collectively referred to as "Arbitrage"). Pursuant to the New RUS Promissory Note and the RUS ARVP Note, the benefit, net of tax, as defined, derived from Arbitrage must be divided as follows: one-third, adjusted for capital expenditures, will be used to make principal payments on the New RUS Promissory Note; one-third will be used to make principal payments on the RUS ARVP Note; and the remaining value may be retained by the Company.

Management is of the opinion that the Company is in compliance with all covenants of the Lease Agreement.

3. UTILITY PLANT

The following summarizes utility plant at December 31:

	2004	2003
Classified plant in service:		
Electric plant—leased	$1,494,222	$1,422,084
Transmission plant	192,601	205,795
General plant	11,629	11,810
Other	67	67
	1,698,519	1,639,756
Less accumulated depreciation	772,938	754,301
	925,581	885,455
Construction in progress	15,068	61,503
Utility plant—net	$ 940,649	$ 946,958

Interest capitalized for the years ended December 31, 2004, 2003 and 2002, was $221, $145, and $42, respectively.

The Company has not identified any legal obligations, as defined in SFAS No. 143, *Accounting for Asset Retirement Obligations*. In accordance with regulatory treatment, the Company records an estimated net cost of removal of its utility plant through normal depreciation. As of December 31, 2004 and 2003, the Company had a regulatory liability of approximately $20,796 and $17,967, respectively, related to non-legal removal costs included in accumulated depreciation.

4. SALE-LEASEBACK

On April 18, 2000, the Company completed a sale-leaseback of two of its utility plants, including the related facilities and equipment. The sale-leaseback provides Big Rivers a $1,089,000 fixed price purchase option, at the end of each lease term (25 and 27 years), which, together with future contractual interest receipts, will be fully funded.

This transaction has been recorded as a financing for financial reporting purposes and a sale for Federal income tax purposes. In connection therewith, Big Rivers received $866,676 of proceeds and incurred $791,626 of related obligations. Pursuant to a payment undertaking agreement with a financial institution, Big Rivers effectively extinguished $656,029 of these obligations with an equivalent portion of the proceeds. The Company also purchased two investments totaling $146,647 to fund the remaining $135,597 of the obligations. These amounts are reflected as restricted investments under long-term lease and obligations related to long-term lease in the accompanying balance sheets. Interest received and paid will be recorded to these accounts over the life of the lease. Currently, the Company is paying 7.57% interest on its obligations related to long-term lease and receiving 6.89% on its related investments. The Company made a $64,000 principal payment on the New RUS Promissory Note with the remaining proceeds. The $75,050 gain was deferred and will be amortized over the respective lease terms, of which the Company recognized $2,824, $2,785, and $2,744, in 2004, 2003, and 2002, respectively. Principal payments begin in 2009.

Amounts recognized in the statement of financial position related to the sale-leaseback as of December 31 are as follows:

	2004	2003
Restricted investments under long-term lease	$ 174,695	$ 168,859
Obligations related to long-term lease	164,704	158,597
Deferred gain on sale-leaseback	62,118	64,941

Amounts recognized in the statement of operations related to the sale-leaseback for the years ended December 31 are as follows:

	2004	2003	2002
Power contracts revenue (revenue discount adjustment, see Note 6)	$ (3,680)	$ (3,680)	$ (3,680)
Interest on obligations related to long-term lease:			
Interest expense	11,548	11,140	10,747
Amortize gain on sale-leaseback	(2,823)	(2,785)	(2,744)
Net interest on obligations related to long-term lease	8,725	8,355	8,003
Interest income on restricted investments under long-term lease	11,278	10,894	10,527
Interest income and other (CoBank patronage allocation)	661	655	727

5. DEBT AND OTHER LONG TERM OBLIGATIONS

A detail of long-term debt is as follows at December 31:

	2004	2003
New RUS Promissory Note, stated amount, $839,071, stated interest rate of 5.75%, with an interest rate of 5.81%, maturing July 2021.	$ 834,601	$ 821,156
RUS ARVP Note, stated amount $256,301, no stated interest rate, with interest imputed at 5.81%, maturing December 2023.	85,814	81,143
LEM Settlement Note, interest rate of 8.0%, payable in monthly installments through July 2023.	17,603	17,999
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 1.27% and 1.06% in 2004 and 2003 respectively), maturing in October 2022.	83,300	83,300
County of Ohio, Kentucky, promissory note, variable interest rate (average interest rate of 1.27% and 1.06% in 2004 and 2003 respectively), maturing in June 2013.	58,800	58,800
Total long-term debt	1,080,118	1,062,398
Current maturities	430	396
Voluntary prepayments	-	8,404
Total long-term debt—net of current maturities and prepayments	$ 1,079,688	$ 1,053,598

The following are scheduled maturities of long-term debt at December 31:

Year	Amount
2005	$ 430
2006	29,102
2007	31,140
2008	39,182
2009	39,234
Thereafter	941,030
Total	$ 1,080,118

RUS Notes—On July 15, 1998, Big Rivers recorded the New RUS Promissory Note and the RUS ARVP Note at fair value using the applicable market rate of 5.81%. The RUS Notes are collateralized by substantially all assets of the Company.

Pollution Control Bonds—The County of Ohio, Kentucky, issued $83,300 of Pollution Control Periodic Auction Rate Securities, Series 2001, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate. These bonds bear interest at a variable rate and mature in October 2022.

The County of Ohio, Kentucky, issued $58,800 of Pollution Control Variable Rate Demand Bonds, Series 1983, the proceeds of which are supported by a promissory note from Big Rivers, which bears the same interest rate as the bonds. These bonds bear interest at a variable rate and mature in June 2013.

The Series 1983 bonds are supported by a liquidity facility issued by Credit Suisse First Boston, and both Series are supported by municipal bond insurance and surety policies issued by Ambac Assurance Corporation. Big Rivers has agreed to reimburse Ambac Assurance Corporation for any payments under the municipal bond insurance policies or the surety policies.

LEM Settlement Note—On the Effective Date, Big Rivers executed the Settlement Note with LEM. The Settlement Note requires Big Rivers to pay to LEM $19,676, plus interest at 8% per annum over the lease term. The principal and interest payment is approximately $1,822 annually. This payment is consideration for LEM's assumption of the risk related to unforeseen costs with respect to power to be supplied to the Aluminum Smelters and the increased responsibility for financing capital improvements.

Other Long-Term Obligations—During 1997, Big Rivers terminated two unfavorable coal contracts. In connection with that settlement, the Company paid $351, $351, and $351 during 2004, 2003, and 2002, respectively. At December 31, 2004, the Company has a remaining liability of $789 payable over the next four years, of which $351 is included in current maturities of long-term obligations.

Notes Payable—Notes payable represent the Company's borrowing on its line of credit with the National Rural Utilities Cooperative Finance Corporation. The maximum borrowing capacity on the line of credit is $15,000, and there were no amounts outstanding on the line of credit at December 31, 2004. The line of credit bears interest at a variable rate. The average interest rate on the line of credit in 2004 was 2.90%. Each advance on the line of credit is payable within one year.

6. RATE MATTERS

The rates charged to Big Rivers' members consist of a demand charge per kW and an energy charge per kWh consumed as approved by the KPSC. The rates include specific rate designs for its members' two classes of customers, the large industrial customers and the rural customers under its jurisdiction. For the large industrial customers, the demand charge is generally based on each customer's maximum demand during the current month. The remaining customers demand charge is based upon the maximum coincident demand of each member's delivery points. The demand and energy charges are not subject to adjustments for increases or decreases in fuel or environmental costs. Big Rivers' current rates will remain in effect until changed by the KPSC.

Effective since September 1, 2000, the KPSC has approved Big Rivers' request for a $3,680 annual revenue discount adjustment for its members through August 31, 2005, effectively passing the benefit of the sale-leaseback transaction (see Note 4) to them. The extent to which Big Rivers requests KPSC approval to continue the adjustment depends upon its planned environmental compliance costs and its overall financial condition. In March 2005, Big Rivers plans to request the KPSC's approval to extend the adjustment through August 31, 2006.

7. INCOME TAXES

The components of the net deferred tax assets as of December 31 were as follows:

	2004	2003
Deferred tax assets:		
Net operating loss carryforward	$ 88,875	$ 96,996
Alternative minimum tax credit carryforwards	3,965	3,582
Sale-leaseback	124,755	119,241
Lease agreement	(9,145)	(2,915)
Total deferred tax assets	208,450	216,904
Deferred tax liabilities:		
Fixed asset basis difference	(18,143)	(27,403)
Other accruals	1,727	1,146
Total deferred tax liabilities	(16,416)	(26,257)
Net deferred tax assets (pre-valuation allowance)	192,034	190,647
Valuation allowance	(188,069)	(187,065)
Net deferred tax asset	$ 3,965	$ 3,582

Big Rivers was formed as a tax-exempt cooperative organization described in Internal Revenue Code Section 501(c)(12). To retain tax-exempt status under this section, at least 85% of the Big Rivers' receipts must be generated from transactions with the Company's members. In 1983, sales to non-members resulted in Big Rivers failing to meet the 85% requirement. Until Big Rivers can meet the 85% member income requirement, the Company is a taxable cooperative. Big Rivers is also subject to Kentucky income tax.

Under the provisions of SFAS No. 109, *Accounting for Income Taxes*, Big Rivers is required to record deferred tax assets and liabilities for temporary differences between amounts reported for financial reporting purposes and amounts reported for income tax purposes. Deferred tax assets and liabilities are determined based upon these temporary differences using enacted tax rates for the year in which these differences are expected to reverse.

At December 31, 2004 and 2003, Big Rivers had a non-patron net operating loss carryforward of approximately $216,771 and $236,576, respectively, for tax reporting purposes expiring 2005 through 2013, and an alternative minimum tax credit carryforward at December 31, 2004 and 2003 of approximately $3,965 and $3,582, respectively, which carries forward indefinitely.

Big Rivers has a net deferred tax asset, against which a valuation allowance has been provided, in part, based upon the fact that it is presently uncertain whether such asset will be realized. The resulting net deferred tax asset at December 31, 2004 and 2003 is approximately $3,965 and $3,582, respectively, that represents the alternative minimum tax credit carryforward, against which no allowance has been provided.

8. POWER PURCHASED

In accordance with the Lease Agreement, Big Rivers supplies all of the members' requirements for power to serve their customers, other than the Aluminum Smelters. Contract limits were established in the Lease Agreement and include minimum and maximum hourly and annual power purchase amounts. Big Rivers cannot reduce the contract limits by more than 12 MW in any year, or by more than a total of 72 MW over the lease term. In the event Big Rivers fails to take the minimum requirement during any hour or year, Big Rivers is liable to LEM for a certain percentage of the difference between the amount of power actually taken and the applicable minimum requirement.

Although Big Rivers will be required by the Lease Agreement to purchase minimum hourly and annual amounts of power from LEM, the lease does not prevent Big Rivers from paying the associated penalty in certain hours to purchase lower cost power, if available, in the open market or reselling a portion of its purchased power to a third party. The power purchases made under this agreement for the years ended December 31, 2004, 2003, and 2002 were $89,696, $79,136 and $73,905, respectively, and are included in power purchased and interchanged on the statement of operations.

9. PENSION PLANS

Big Rivers has non-contributory defined benefit pension plans covering substantially all employees who meet minimum age and service requirements. The plans provide benefits based on the participants' years of service and the five highest consecutive years' compensation during the last ten years of employment. Big Rivers' policy is to fund such plans in accordance with the requirements of the Employee Retirement Income Security Act of 1974.

The following is an assessment of the Company's non-contributory defined benefit pension plans at December 31:

	2004	2003
Projected benefit obligation	$ (15,931)	$ (13,164)
Fair value of plan assets	11,982	10,106
Funded status	$ (3,949)	$ (3,058)

The accumulated benefit obligation for all defined benefit pension plans was $11,359 and $9,087 at December 31, 2004, and 2003, respectively.

Amounts recognized in the statement of financial position at December 31:

	2004	2003
Prepaid benefit cost	$ 239	$ 351
Net amount recognized	$ 239	$ 351

Net periodic pension costs, which are calculated based on actuarial assumptions at January 1, were as follows for the years ended December 31:

	2004	2003	2002
Benefit cost	$ 954	$ 995	$ 735
Employer contribution	843	823	809
Benefits paid or transferred	103	937	426

Assumptions used to develop the projected benefit obligation were:

	2004	2003	2002
Discount rates	5.75 %	6.25 %	6.75 %
Rates of increase in compensation levels	4.00	4.00	4.00
Expected long-term rate of return on assets	7.50	7.50	7.50

The expected long-term rate of return on plan assets for determining net periodic pension cost for each fiscal year is chosen by the Company from a best estimate range determined by applying anticipated long-term returns and long-term volatility for various asset categories to the target asset allocation of the plans, as well as taking into account historical returns.

Using the asset allocation policy adopted by the Company noted in the paragraph below, we determined the expected rate of return at a 50% probability of achievement level based on (a) forward-looking rate of return expectations for passively-managed asset categories over a 20-year time horizon and (b) historical rates of return for passively-managed asset categories. Applying an approximately 80%/20% weighting to the rates determined in (a) and (b), respectively, produced an expected rate of return of 7.38%, which was rounded to 7.50%.

The general investment objectives are to invest in a diversified portfolio, comprised of both equity and fixed income investments, which are further diversified among various asset classes. The diversification is designed to minimize the risk of large losses while maximizing total return within reasonable and prudent levels of risk. The investment objectives specify a targeted investment allocation for the pension plans of up to 55% equities. The remaining 45% may be allocated among fixed income or cash equivalent investments. Objectives do not target a specific return by asset class. These investment objectives are long-term in nature. As of December 31, 2004, the investment allocation was 54% equities and 46% fixed income.

Expected retiree pension benefit payments projected to be required during the years following 2004 are:

Year	Amount
2005	$ 584
2006	675
2007	598
2008	1,342
2009	678
2010 - 2014	7,521
Total	$ 11,398

In 2005, the Company expects to contribute $923 to its pension plan trusts.

10. POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

Big Rivers provides certain postretirement medical benefits for retired employees and their spouses. As of July 1, 2001, Big Rivers pays 85% of the cost from age 62 to 65 for all retirees. For salaried employees who retired prior to December 31, 1993, Big Rivers pays 100% of Medicare supplemental costs. For salaried employees who retire after December 31, 1993, Big Rivers pays 25% plus $25 per month of the Medicare supplemental costs.

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act") was enacted. The Medicare Act introduces a Medicare prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least "actuarially equivalent" to the Medicare benefit. The underlying determination of whether an employer's plan qualifies for the federal subsidy is still subject to clarifying federal regulations related to the Medicare Act. When this guidance is issued, the Company will reassess if its plan qualifies for the subsidy. However, the Company currently believes that the benefits provided under the plan do not meet the definition of actuarially equivalent.

The discount rate used in computing the postretirement obligation was 6.25% for 2004 and 6.75% for 2003. A health care cost trend rate of 11.0% in 2004 declining to 5.5% in 2011 was utilized.

The following is an assessment of the Company's postretirement plan at December 31:

	2004	2003
Total benefit obligation	$ (3,440)	$ (3,122)
Unfunded accrued postretirement cost	(3,662)	(3,541)

The components of net periodic postretirement benefit costs for the years ended December 31, which are calculated based on actuarial assumptions at January 1, were as follows:

	2004	2003	2002
Benefit cost	$ 310	$ 277	$ 267
Benefits paid	188	175	173

Expected retiree benefit payments projected to be required during the years following 2004 are:

Year	Amount
2005	$ 212
2006	209
2007	228
2008	240
2009	264
2010 - 2014	1,496
Total	$ 2,649

In addition to the postretirement plan discussed above, in 1992 Big Rivers began a postretirement benefit plan which vests a portion of accrued sick leave benefits to salaried employees upon retirement or death. To the extent an employee's sick leave hour balance exceeds 480 hours, such excess hours are paid at 20% of the employee's base hourly rate at the time of retirement or death. The accumulated obligation recorded for the postretirement sick leave benefit is $259 and $231 at December 31, 2004 and 2003, respectively. The postretirement expense recorded was $28, $51 and $32 for 2004, 2003 and 2002, respectively, and the benefits paid were $-0-, $21, and $-0- for 2004, 2003, and 2002 respectively.

11. BENEFIT PLAN—401(K)

Big Rivers has two defined contribution retirement plans covering bargaining and salaried employees. Big Rivers matches up to 60% of the first 6% of eligible employees' wages contributed. Employees generally become vested in Company matching contributions based upon years of service as follows:

Years of Vesting Service	Vested Percentage
1	20%
2	40%
3	60%
4	80%
5 or more	100%

Employees are also permitted to make pre-tax contributions of up to 75% of eligible wages. Big Rivers' expense under this plan was $168, $160, and $155 for the years ended December 31, 2004, 2003, and 2002, respectively.

12. RELATED PARTIES

For the years ended December 31, 2004, 2003, and 2002, Big Rivers had tariff sales to its members of $105,004, $103,118, and $108,440, respectively. In addition, for the years ended December 31, 2004, 2003, and 2002, Big Rivers had certain sales to Kenergy for the Aluminum Smelters and Weyerhaeuser loads, of $43,017, $26,327, and $7,581 respectively.

At December 31, 2004 and 2003, Big Rivers had accounts receivable from its members of $12,128 and $11,359, respectively.

13. COMMITMENTS AND CONTINGENCIES

Big Rivers is involved in litigation arising in the normal course of business. While the results of such litigation cannot be predicted with certainty, management, based upon advice of counsel, believes that the final outcome will not have a material adverse effect on the financial statements.

* * * * * *

Item 12) State each material fact and purpose which incents or otherwise motivates Big Rivers to seek or otherwise accept the Unwind Transaction and Lease Agreement termination which is the subject of this proceeding. Discuss each such listed material fact and purpose.

Response) In addition to answers provided to the AG's questions 1 and 43 the material facts that incent the Unwind Transaction, including the $623 million from E. ON, are listed in Exhibit CWB-2 and described in the testimony of C. William Blackburn, Exhibit 10, pages 12 through 14. Additional information as to the $327 million of present value compensation in cash and increased power purchase payments from the Smelters is further explained in the answer to AG question 67.

Witness) Michael H. Core

Item 13) Under the existing Lease Agreement, state the entity which is responsible for capital investments necessary to meet "clean air" requirements, emission standards and any other environmental rules and requirements.

a. State how the costs of those investments are recovered, and which entity pays for such costs.

Response) See E.ON's response.

Witness) E.ON. U.S.

Item 14) Under the existing Lease Agreement, state the entity which is responsible for incurrence of operating expenses necessary to meet "clean air" requirements, emission standards and any other environmental rules and requirements.

a. State how the costs of those operating expenses are recovered, and which entity pays for those costs ultimately under the Lease Agreement, and how that entity pays for such costs.

Response) See E.ON's response.

Witness) E.ON. U.S.

Item 15) State the reasons why it is not in the public interest to simply continue the Lease Agreement under its present terms. Also, state any necessary revisions to the Lease Agreement that would make it such that it could be continued in the public interest.

Response) Big Rivers believes the Unwind is advantageous to Big Rivers, its Members and Western Kentucky generally. That being the case, it is not in the public interest to continue in the existing transaction, which is less advantageous to that group. There is no conceivable amendment to the arrangements with the E.ON entities under the Lease Agreement and the Power Purchase Contract that can provide the advantages to Big Rivers, its Members and Western Kentucky that are available through the Unwind, such as providing an acceptable wholesale power supply source for the Smelters. See the responses to AG questions 1 and 43. See also E.ON's response.

Witness) Michael H. Core
E. ON. U.S.

Item 16) State the reasons why it is not in the public interest to simply continue the Purchase Power Agreement under its present terms. Also, state any necessary revisions to the Purchase Power Agreement that would make it such that it could be continued in the public interest.

Response) See answer to Item 15, immediately above.

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 17) Provide any available and current market and industry research on aluminum commodity markets and aluminum smelting that have been reviewed and considered by Big Rivers.

Response) Big Rivers is a subscriber of Metals Week, and we have tracked the monthly average price of aluminum for the United States market over the last four years. Big Rivers is prohibited from providing these reports due to the copyright laws.

Big Rivers has general knowledge from multiple publications and reports concerning metals demand growth projections. See attached.

Witness) C. William Blackburn

Jim Miller

From: Mudge, Robert [RMudge@crai.com]
Sent: Tuesday, July 31, 2007 3:27 PM
To: Lyon, Carl; mcore@bigrivers.com; mbailey@bigrivers.com; dspainhoward@bigrivers.com; bblackburn@bigrivers.com; Jim Miller; Drefke, Kyle; Michel, Robert; jgaines@jdg-llc.com
Subject: RE: WSJ article

Here it is:

PAGE ONE

COMMODITY KING
Aggressive Swiss Giant Rides Resources Boom

Successor to Marc Rich,
Glencore Gains Power
As Trader, Producer Too

By ANN DAVIS
July 31, 2007; Page A1

BAAR, Switzerland -- When the fugitive commodities dealer Marc Rich sold his trading firm 13 years ago, it was best known for doing business with pariah nations.

Since he left, the intensely private company -- renamed Glencore International AG -- has leveraged itself into an industrial colossus, with a stronger grip over more individual markets for the earth's riches than almost any other single company.

TRADE SECRETS

• **Background:** Closely held Glencore, successor to Marc Rich trading firm, is a leading dealer in many commodities.
• **Getting More Corporate:** Glencore has publicly traded debt and owns large chunks of publicly held producers such as Switzerland's Xstrata PLC.
• **Bottom Line:** In commodities boom, little-known giant plays an influential role, including helping to spur recent consolidation in the metals industry.

Glencore is one of the world's largest suppliers of aluminum, nickel, zinc and lead. It is a major seller of oil, grains and sugar as well. Along with its affiliates, Glencore says, it ships more coal on the high seas than any other competitor.

Glencore also has played a behind-the-scenes role in the recent extensive consolidation of the commodities industry. The takeover battle for Canada's aluminum leader, **Alcan** Inc., arose after Glencore combined assets with Russian companies to create a giant that knocked **Alcoa** Inc. off its perch as the largest producer. In a bruising fight over nickel, Glencore helped an affiliate win a lengthy, multisided battle for Canadian miner Falconbridge Ltd.

The story of Glencore's evolution from rogue trader to one of the most powerful private companies in the world was pieced together from interviews with people with intimate knowledge of the company and from documents such as bond prospectuses. The firm has long been willing to deal in virtually any commodity around the globe, from cobalt in war-ravaged Congo to crude oil from Saddam Hussein's Iraq. Its longstanding knowledge and connections in isolated or unstable regimes sometimes give Glencore access to resources at good prices because it can tap opportunities that not everyone is going after. Glencore has said its policy is to require its companies and their employees to comply with any economic sanctions in force in countries where they do business.

Its trading prowess and a drive to acquire production assets like mines and smelters have made Glencore one of the biggest winners in the commodities boom. Its revenue last year was $116.5 billion, besting by about 30% the largest private company in the U.S., Koch Industries Inc. Glencore's profits of $5.3 billion were more than triple the fiscal '06 net of the far-better-known private commodity merchant Cargill Inc.

WHERE IS MARC RICH TODAY?


1

Watch a video[2] in which Mr. Rich accepts an honorary degree awarded to him in Israel, posted on his firm's Web site[3].

A small number of people share these riches. The top 12 Glencore executives saw the value of their stakes in the employee-owned company soar an average of $87 million each last year -- more than three times the stock-related pay of **Goldman Sachs Group**'s chief executive. And the top 67 people at Glencore reaped other pay and benefits averaging $8 million.

As Glencore moves more into the corporate mainstream -- floating billions of dollars worth of publicly traded debt -- the company still struggles to convince some skeptics it's a different animal from the firm Mr. Rich founded and left long ago. Not helping is a 2005 report from a United Nations investigative committee saying Glencore paid millions of dollars in kickbacks earlier this decade to gain access to Saddam Hussein's petroleum under the oil-for-food program. Glencore told the U.N. it didn't sanction any bribes.

The evolution of the Swiss company owes much to its chief executive, Ivan Glasenberg, 50 years old, a skilled coal trader and onetime South African race-walking champion. He operates from the home offices in Baar, in a low-tax Swiss canton, to which employees from around Zurich travel in purple vans bearing a logo in gold letters swimming in black oil. The firm's white-and-glass headquarters contrast with some old-world touches: receptionists in immaculate suits, fine china to serve guests lunch, and tingling cowbells in Alpine pastures outside.

One of Mr. Glasenberg's moves has been to package production assets the trading firm owns into affiliated publicly traded companies, much of whose output Glencore then markets. The result is to amplify its market power. Glencore moves so much metal that it at times holds 50% to 90% of the nickel and aluminum scheduled for delivery in London Metal Exchange warehouses, according to traders who know who holds positions on the exchange.


Ivan Glasenberg

Such aggressive moves aren't illegal: Commodities markets allow producers considerable trading leeway to manage their price risks. Glencore has been able to counter occasional probes into suspected market manipulation, such as in the aluminum market, by arguing that its production operations led it to do what seemed like heavy buying or selling.

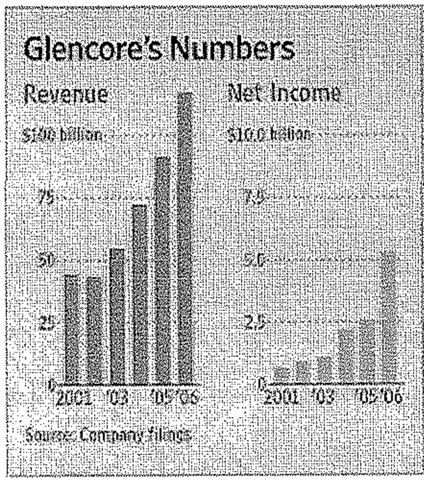
"There is no other company like Glencore that plays in so many fields. In these markets, suppliers are in the driver's seat," says Markus Moll, a metals industry analyst in Austria who advises specialty steelmakers.

Glencore's history traces to 1974, when Mr. Rich founded a trading firm of his own after a fractious departure from Philipp Brothers, a storied metals and oil trader. In 1983 the U.S. Justice Department charged Mr. Rich with tax evasion and with buying oil from Iran while it held U.S. hostages. He fled to Switzerland, where his firm was based. It and its former U.S. unit later pleaded guilty to some of the charges and agreed to a nearly $200 million settlement, but Mr. Rich remained a fugitive.

His status hung over Marc Rich & Co. AG until 1994, when some of Mr. Rich's lieutenants bought him out for about $500 million and the firm took the name Glencore. They raised the money partly by selling a 15% stake to a pension fund of Swiss pharmaceutical giant **Roche Holding** AG, several former partners say. Roche says it doesn't comment on investments. Glencore bought back the interest a few years ago. As for Mr. Rich, he set up other trading firms bearing his name, some of which he still owns. President Clinton pardoned him upon leaving office in 2001.

At the time of the buyout, Mr. Glasenberg was among the trading firm's rising stars. He had gained a reputation as a relentless negotiator who, among other things, was able to find buyers for coal from his native South Africa when it was widely boycotted because of its apartheid racial policy.

Glencore has a network of some 50 outposts in more than 40 countries, manned by field officers. Among their roles is to meet with commodity suppliers and consumers, trying to gauge inventory levels and estimate local demand. The network has sometimes drawn comparisons to the Central Intelligence Agency. Beyond gathering information, the job may involve practical chores like imploring civil servants for an industrial permit or even going down to the docks to yell at longshoremen so a shipment of metal or grain gets out of port, veterans of the system say.



Employees in the "traffic" department work with these agents -- chartering vessels and sometimes diverting them to more valuable assignments. Both field officers and the traffic crew are alert for signs of local shortages or oversupplies, information that gives Glencore traders an advantage.

Traders are the stars around which the system revolves. The common trader image is of a person glued to a computer screen making rapid-fire bets on futures. But Glencore's traders are frequently on the road. They focus on matters like whether coal can be delivered more cheaply by shipping it from one location than from another, or whether the firm could sell a refined metal more profitably if it owned the raw ore instead.

When Mr. Glasenberg was running the coal division in the 1990s, he determined that rather than just trade coal, the firm should buy coal mines. Depressed coal prices made mines easy to buy. Mr. Glasenberg persuaded his partners to spend a couple of hundred million dollars to acquire mines in Australia and South Africa. He told the engineers running them to focus on costs and production and leave the selling to him. He then set the firm's ferocious marketing machine to work.

Mr. Glasenberg became chief executive in 2002. That year, amid another beaten-down commodities market, Glencore folded its coal mines into a small producer of zinc and alloys that it partly owned. This company, **Xstrata PLC**, agreed to buy the coal assets for $2.5 billion and simultaneously listed its shares on the London Stock Exchange. Glencore's chairman, Willy Strothotte, is also chairman of Xstrata.

That company then went on an acquisitive tear, quickly becoming the world's fifth-largest mining company. Xstrata's soaring stock has hoisted the value of Glencore's 35% stake in it to $21 billion.

Xstrata is just the most visible of Glencore's public affiliates. Beginning in 1987, Glencore bought interests in several aluminum-production plants. In 1996 it combined some of them into Century Aluminum Co., which it floated on the Nasdaq Stock Market. Century now is North America's third-largest aluminum producer. Glencore, which owns 29% of it, sells it raw materials and buys part of its aluminum output.

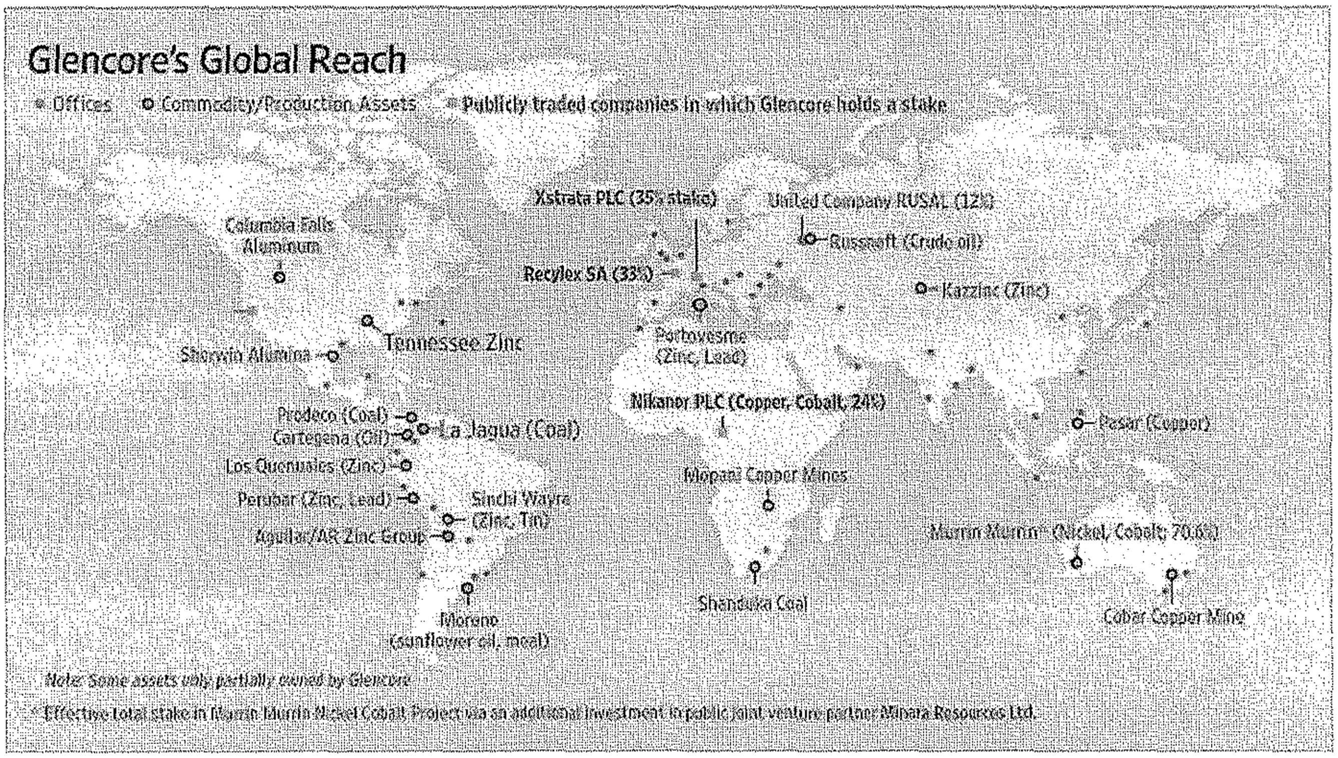
In such deals, when the affiliated companies later acquire more assets, Glencore's command of the market often rises as well. One Glencore customer, Max Crosland, head of fuels and logistics at a British coal-fired power station, says he buys from the company partly because he knows Glencore has deep access to supply. "The more confident we are in our coal supplier, the less inventory we can hold," he says.

Glencore also gets fees for its marketing efforts. At Xstrata, Glencore takes a cut of 3.5% to 5% of most sales of ferrochrome and vanadium, a metal used to strengthen steel. Glencore gets 50 cents for every ton of South African and Australian coal Xstrata exports, in exchange for its advice and market intelligence. In nickel, Glencore shares profits when it gets Xstrata prices above a certain level.

The Glencore-Xstrata relationship has stirred concerns about their collective market clout, particularly in thinly traded markets where there aren't transparent futures exchanges. For instance, in 2002, bond filings show, Xstrata controlled 24% of the market for vanadium and Glencore was Xstrata's exclusive marketer of the metal. With Glencore's early input, Xstrata had launched a vanadium mine in Western Australia.

Soon after the costly mine opened, a vanadium surplus led to rock-bottom prices. This was bad both for Glencore, which had agreed to buy some of Xstrata's production elsewhere at prices that were now too high, and for Xstrata, which had sunk money into a money-losing mine with operational problems.

Xstrata halted the mine's production in early 2003 and permanently shut it in 2004. It dismantled the equipment, making the mine hard to restart, and it closed another vanadium mine elsewhere as well. With all this production taken out, the metal's price soared -- quintupling by the end of 2004, according to price provider Ryan's Notes.



Western Australia officials, incensed at the mothballing of a mine that taxpayer funds had helped develop, launched an investigation. A disgruntled local partner on the mine project told the investigators that Glencore was sitting on a stockpile of vanadium and had a motive to push the price up.

Xstrata told the officials no one could manipulate the price of vanadium because some of the metal always gets produced regardless of demand, as it's a byproduct of steelmaking. Xstrata argues that it wouldn't have abandoned a mine costing hundreds of millions of dollars to help Glencore reverse far smaller losses. It also notes that a corruption probe later revealed that its disgruntled mine partner had helped script the eventual investigative report. That report said Xstrata's actions were a factor in higher prices but it didn't allege market manipulation.

Glencore is known for overcoming obstacles to delivery. Last year it was able to get coal to Israel despite problems gumming up shipments from Russia. "They will always find a way," says Moshe Bornstein, head of Israel's National Coal Supply Corp.

One of Glencore's most far-reaching moves was in aluminum. In 2004 it won an auction for Jamaican properties that mine and refine bauxite, a raw material for aluminum, that were also coveted by a company controlled by Russian oligarch Oleg Deripaska. Over two years, as Mr. Deripaska and another Russian aluminum producer discussed a combination, Mr. Glasenberg offered to link up with them by contributing the Jamaican assets and some others to a joint enterprise.

The result was the formation this year of the aluminum giant known as United Co. Rusal, of which Glencore owns 12%. After the deal closed, Alcoa, which had been the largest producer of primary aluminum, tried to keep up by acquiring Alcan, only to be outbid by the Anglo-Australian Rio Tinto.

Glencore's relationship with the well-connected Mr. Deripaska may serve it well. One of his companies is poised to take control of a Russian oil producer from a businessman who fell out of favor with the Kremlin. Glencore has managed to keep its large stake in many of that Russian oil producer's assets, people familiar with the deal say.

Distancing itself from its Marc Rich past has been a challenge for Glencore at times. The 2005 U.N. report on Iraq oil-for-food abuses accused Glencore and a firm then controlled by Mr. Rich of separate but similar kickback schemes to get access to Iraqi oil. The report, which also implicated other companies, said that in the early 2000s, Glencore made cash payments to one of its agents, and this agent made cash payments to an Iraqi diplomatic office in Geneva. Glencore called the payments a "success fee," the U.N. report says. Glencore told the U.N. panel that "if it turns out" anyone paid bribes, that person violated instructions not to do so.

The onetime Marc Rich entity cited in the U.N. report denied wrongdoing. Mr. Rich's current investment firm says it isn't aware of any investigation of him. Based largely on the U.N. findings, the Swiss attorney general's office is conducting a criminal investigation into a number of companies, which it won't identify.

Even Glencore's publicly held affiliates sometimes are dogged by its history of trading with pariah nations. Xstrata recently encountered questions about Glencore when Xstrata sought to buy a uranium miner in Australia. The government there said it could do so but imposed a requirement to consult authorities before allowing anyone else to market the uranium. Ultimately, Xstrata didn't do the acquisition.

Glencore officials "are under pressure to prove they're respectable" as they deepen their ties to banks and issue debt, says Mark Pieth, a Swiss law professor and one of the three U.N. panel members who investigated the Iraq oil-for-food arrangement. Glencore has sold more than $5 billion in bonds since 2003. Mr. Pieth says it is working to strengthen its compliance systems, though "it's coming a bit late."

Bond investors focus on Glencore's thriving business. In its latest debt offering earlier this year, in London, bond investors offered to lend Glencore 10 times what it initially sought.

At Loomis Sayles & Co., a money manager that bought Glencore bonds in 2004, Diana Monteith, a fixed-income analyst, says bondholders' interests are aligned with those of Glencore's shareholders. "Everyone [at Glencore] is really incented to make sure there are good controls," she says, because if someone makes a bad bet, "everybody's net worth will go down rapidly."

Glencore employee shareholders, who number 417 in all, can't access their equity unless they leave the company. Departing employees must sell their stakes back to the company.

This arrangement can require Glencore to lay out big cash payments when some executives who have accumulated tens or hundreds of millions of dollars of wealth look to cash out. Rating agencies say there's a risk Glencore could face a run for the exits during the current good times. Mr. Glasenberg has told investors that shareholder turnover is planned and orderly.

--Glenn R. Simpson, Paul Glader and David Gauthier-Villars contributed to this article

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From: Lyon, Carl [mailto:clyon@orrick.com]
Sent: Tuesday, July 31, 2007 4:22 PM
To: mcore@bigrivers.com; mbailey@bigrivers.com; dspainhoward@bigrivers.com; bblackburn@bigrivers.com; jmiller@smsmlaw.com; Drefke, Kyle; Michel, Robert; jgaines@jdg-llc.com; Mudge, Robert
Subject: WSJ article

There is a lead article in the Journal on Glencore. Mentions Century as 3rd largest producer in North America. Can't send from my BB.

Sent from my BlackBerry Wireless Handheld (www.BlackBerry.net)

FILE

19

AEP AMERICAN ELECTRIC POWER

Legal Department

RECEIVED-DOCKETING DIV

2006 NOV 21 PM 1:37

PUCO

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
aep.com

November 21, 2006

Ms. Renee J. Jenkins
Secretary of the Commission
Public Utilities Commission of Ohio
180 East Broad Street
Columbus, OH 43215-3793

Marvin I. Resnik
Assistant General Counsel -
Regulatory Services
(614) 716-1606
(614) 716-2950 (fax)
miresnik@aep.com

Re: Case No. 05-1057-EL-CSS

Dear Secretary Jenkins:

The Commission's Supplemental Opinion and Order in this docket, dated November 8, 2006, directed that an executed copy of the electric service agreement between AEP Ohio and Ormet shall be filed in this docket within 15 days after execution of the agreement. To that end AEP Ohio is filing copies of the agreement which was executed on November 8, 2006.

Very truly yours,

Marvin I. Resnik

MIR:llg
Attachments

cc: Parties of Record

This Contract entered into this 8th day of ~~October~~ November 2006, by and between Columbus Southern Power Company and Ohio Power Company, hereafter called AEP Ohio, and Ormet Primary Aluminum Corporation, 1233 Main Street, Wheeling, West Virginia 26003, hereafter called the Customer,

Witnesseth:

For and in consideration of the mutual covenants and agreements hereinafter contained, the parties hereto agree with each other as follows:

AEP Ohio agrees to furnish to the Customer, during the term of this Contract, and the Customer agrees to take from AEP Ohio, subject to AEP Ohio's standard Terms and Conditions of Service as regularly filed with the Public Utilities Commission of Ohio (Commission) and the terms and conditions as set forth in the Stipulation and Recommendation in Case No. 05-1057-EL-CSS as approved by the Commission which is attached hereto and hereby made a part of this Contract, all the electric energy of the character specified herein that shall be purchased by the Customer in the premises located at the Customer's Hannibal, Ohio facilities. In the event the regularly filed Terms and Conditions of Service conflict with the terms and conditions set forth in the Stipulation and Recommendation, the latter terms and conditions will be controlling.

AEP Ohio is to furnish and the Customer is to take electric energy under the terms of this Contract for a period of up to 24 months from the time such service is commenced and ending at midnight on December 31, 2008. The date that service shall be deemed to have commenced under this Contract shall be the later of January 1, 2007 or the effective date of the Stipulation in Case No. 05-1057-EL-CSS.

The electric energy delivered hereunder shall be alternating current at approximately 138,000 volts, 3-wire, 3-phase and it shall be delivered at the interconnection of AEP Ohio's two double-circuit 138-kV steel tower transmission lines with the Customer's two double-circuit 138-kV steel tower transmission lines (i.e. in Ohio Township, Monroe County, Ohio at Tower 39 on double circuit Line #1 and at Tower 38 on double circuit Line #2), which shall constitute the point of delivery under this Contract. The said electric energy shall be delivered at reasonably close maintenance to constant potential and frequency, and it shall be measured by a meter or meters owned and installed by AEP Ohio and located at the Kammer Substation.

The Customer's contract capacity is hereby fixed at 520,000 kW/kVA. Beginning July 1, 2007, the minimum billing demand for this Contract shall be 312,000 kW/kVA.

There are no unwritten understandings or agreements relating to the service herein above provided. This Contract shall be in full force and effect when signed by the authorized representatives of the parties hereto, subject to the approval of the Public Utilities Commission of Ohio in Case No. 05-1057-EL-CSS.

The Customer agrees that its electrical facilities shall not be interconnected with any facilities other than AEP Ohio's facilities unless written authorization is received from AEP Ohio.

Columbus Southern Power Company Ohio Power Company	Ormet Primary Aluminum Corporation
By: Mark Gundelfinger (Signature)	By: [signature] (Signature)
Mark Gundelfinger (Printed Name)	Ken Campbell (Printed Name)
Title: Manager - Customer Services	Title: CEO
Date: 11/9/06	Date: 11/8/2006

Joint Ex. 2

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Complaint of Ormet Primary Aluminum Corporation and Ormet Aluminum Mill Products Corporation	)	
Complainants	)	
v.	)	**Case No. 05-1057-EL-CSS**
South Central Power Company and Ohio Power Company	)	
Respondents	)	

STIPULATION AND RECOMMENDATION

Rule 4901-1-30, Ohio Administrative Code ("OAC") provides that any two or more parties to a proceeding may enter into a written or oral stipulation covering the issues presented in such a proceeding. The purpose of this document is to set forth the understanding of the parties who have signed below (the "Signatory Parties") and to recommend that the Public Utilities Commission of Ohio (the "Commission") approve and adopt, as part of its Opinion and Order in this proceeding, this Stipulation and Recommendation (the "Stipulation") resolving the issues in the above-captioned proceeding. This Stipulation is fully supported by data and information contained in the evidence in the record in this proceeding; represents a just and reasonable resolution of such issues in this proceeding; violates no regulatory principle or precedent; benefits, as a package, ratepayers and the public interest; and is the product of lengthy, serious bargaining among knowledgeable and capable parties in a cooperative process undertaken by the Signatory Parties to settle this case. While this Stipulation is not binding on the Commission, it is entitled to careful consideration by the Commission, where, as here, it is sponsored by parties representing a wide range of interests, including the Commission's Staff. For the purpose of resolving all issues raised by this proceeding, the Signatory Parties stipulate, agree and recommend as set forth below.

This Stipulation is entered into by and among Columbus Southern Power Company (CSP) and Ohio Power Company (OPCO) (collectively, "AEP Ohio"), both of which are electric utility operating companies of the American Electric Power ("AEP") system, Ormet Primary Aluminum Corporation and Ormet Aluminum Mill Products Corporation (collectively, "Ormet"), South Central Power Company ("SCP"), United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union ("USW"), Ohio Energy Group ("OEG") and the Commission's Staff. Intervenor Industrial Energy Users-Ohio ("IEU"), while not a Signatory Party, has agreed not to oppose the Commission's approval of this Stipulation. All Signatory Parties fully support this Stipulation and urge the Commission to accept and approve the terms hereof.

WHEREAS, in Case No. 96-999-EL-AEC, OPCO applied to the Commission for approval of a special contract arrangement with Ormet (the "Interim Agreement") which would become effective upon the November 30, 1997 termination of the then-current service agreement between OPCO and Ormet, and would terminate at midnight on December 31, 1999;

WHEREAS, in Case No. 96-1000-EL-PEB, OPCO and SCP jointly petitioned the Commission for reallocation of their certified service territories so that Ormet, then a customer of OPCO, would become a customer of SCP upon termination of the Interim Agreement;

WHEREAS, by Finding and Order in Case Nos. 96-999-EL-AEC and 96-1000-EL-PEB, dated November 14, 1996, the Commission approved the Interim Agreement and the request of OPCO and SCP to reallocate their certified territorial boundaries so that Ormet would become a customer of SCP upon termination of the Interim Agreement;

WHEREAS, pursuant to the terms of a Curtailment and Indemnity Agreement, which was an exhibit to the joint petition in Case No. 96-1000-EL-PEB, after Ormet became a customer of SCP and Ormet's load was removed from the AEP system's control area, OPCO and the AEP system no longer had either the right or obligation to resume control area responsibility for Ormet's load;

WHEREAS, Ormet and SCP entered into a service agreement which provided for the sale by SCP of a maximum 20 MW of electric power and energy to Ormet (5 MW firm, 15 MW interruptible) and for Ormet to obtain from third parties in the market the remaining electricity to service the load for its facilities in Hannibal, Ohio;

WHEREAS, the initial SCP/Ormet service agreement was modified to terminate any obligation of Ormet to buy, and of SCP to sell to Ormet, electric power and energy;

WHEREAS, subsequent to the modification of the initial SCP/Ormet service agreement, Ormet filed for Chapter 11 bankruptcy protection and emerged from bankruptcy in April 2005;

WHEREAS, Ormet curtailed operations at its Hannibal, Ohio facilities in January 2005 and those operations have not been restarted;

WHEREAS, on August 25, 2005, Ormet filed in this docket a petition to transfer rights to furnish electric service and/or to reallocate certified service territories, along with a complaint against OPCO alleging that OPCO was proposing to impose unjust, unreasonable and discriminatory rates if Ormet were to return to OPCO's certified service territory;

WHEREAS, on June 14, 2006, the Commission issued an Opinion and Order in this docket which, among other things:

1. found that the bankruptcy court authorized the rejection of the service agreement between SCP and Ormet and which deferred to that determination

2. found that SCP is legally obligated to serve Ormet's 520 MW load

3. found that, in the context of service to Ormet, SCP does not provide, or propose to provide, physically adequate service

4. directed that a second hearing should be held regarding: whether SCP's failure to propose to provide physically adequate service has been corrected or can be corrected under reasonable operating conditions; whether the Commission should authorize another supplier to serve Ormet; or whether the Commission should order such other remedy authorized by law

5. directed that the issue of an appropriate rate to be charged by OPCO for service to Ormet should be addressed after the Commission completes its proceedings under § 4933.83(B), Ohio Rev. Code, and determines whether another electric supplier should be authorized to serve Ormet.

WHEREAS, on July 14, 2006, SCP and OPCO each filed rehearing applications regarding the June 14, 2006 Opinion and Order;

WHEREAS, on August 9, 2006, the Commission issued an Entry on Rehearing in this docket which denied the rehearing applications filed by SCP and by OPCO;

WHEREAS, on August 25, 2006, SCP filed a second rehearing application which the Commission denied in its September 13, 2006 Second Entry on Rehearing;

WHEREAS, on October 6, 2006, SCP filed a Notice of Appeal to the Supreme Court of Ohio (Case No. 06-1866) regarding the Commission's June 14, 2006 Opinion and Order, August 9, 2006 Entry on Rehearing and September 13, 2006 Second Entry on Rehearing;

WHEREAS, according to Ormet Ex. 4:

1. When Ormet's Hannibal facilities are fully operating it employs approximately 1,000 people with total annual wages of about $40,000,000

2. Ormet covers approximately 3,300 of its employees and family members' health care at a cost exceeding $10,000,000 per year

3. Ormet pays about $1,000,000 annually in taxes to Monroe County, Ohio and its school district

4. Ormet purchases about $15,000,000 to $18,000,000 of goods and services every year in the Monroe County area

5. Ormet has been one of Southeastern Ohio's largest employers, particularly of skilled workers such as those who comprise the USW

6. If Ormet is unable to resume operation of its Hannibal facilities there will be no jobs to which the USW laborers can return

7. If the Hannibal, Ohio region loses the significant tax revenues and capital spending Ormet historically has brought to that region, the economy in that region will become further depressed

WHEREAS, as reflected in Ormet Ex. 2, Ormet has characterized its load at full operation as 520 MW at a 99% load factor;

NOW, THEREFORE, the Signatory Parties stipulate, agree and recommend that the Commission make the following findings and issue its Opinion and Order in these proceedings in accordance with the following:

1) CSP shall be permitted to intervene in this docket.

2) Based upon the anticipated acceptance by the Commission of this Stipulation, without modification, the Commission should consider the Stipulation as presenting a joint petition submitted by CSP, OPCO and SCP under § 4933.83 (E), Ohio Rev. Code, which statute, in pertinent part, provides that:

> any two or more electric suppliers may jointly petition the commission for the reallocation of their own territories and electric load centers among them and designating which portions of such territories and electric load centers are to be served by each of the electric suppliers.

Further, the Commission should find that approval of such joint petition is not contrary to the public interest and, therefore, meets the standard of § 4933.85, Ohio Rev. Code, for approval of the joint petition.

3) The Commission will reallocate the service territories of CSP and OPCO and SCP such that Ormet's Hannibal facilities will be located in a joint CSP/OPCO certified service territory effective January 1, 2007. SCP shall have no obligation to provide electric service to Ormet's Hannibal facilities prior to January 1, 2007. Provided, however, that SCP will retain its service obligation prior to, on, and after January 1, 2007 with respect to:

   1. Flashing light and sign for the Ormet Plant on Route 7 to the west of the Ormet Plant (South Central Account No. 846-201-006). Installed 4/6/1998.

   2. Ormet employee park just to the south of Route 7 and to the east of the Ormet Plant (South Central Account No. 846-153-001). Installed 6/1/1982.

   3. Sign for the Ormet Plant on Route 7 to the east of the Ormet Plant (South Central Account No. 846-151-001). Installed 8/1/1965.

4) As part of this Stipulation, Ormet has entered into an electric service contract (Contract) which reflects the provisions of this Stipulation which are applicable to the Contract. The Contract, a copy of which is attached as Attachment I, shall be deemed to have been approved by the Commission as part of the Commission's approval of the Stipulation.

5) Generation, transmission and distribution service will be supplied by AEP Ohio. Such service will meet Ormet's peak demand of approximately 520 MW at a 99% load factor (full operation). AEP Ohio's generation service (which will be

supplied one-half (50%) by CSP and one-half (50%) by OPCO) will be supplied only for consumption at Ormet's Hannibal, Ohio facilities and such power and energy will not be resold or transferred by Ormet, regardless of any opportunities for such transactions.

6) This Stipulation will become effective upon approval in a final order of the Commission. Should the Commission's final order be appealed to the Supreme Court, or become involved in some other judicial process, this Stipulation and the related Contract will be suspended for the duration of such appeal or other process and/or during any remand to the Commission. Prior to January 1, 2009, Ormet shall not switch to service from a Competitive Retail Electric Service Provider. Ormet cannot initiate any proceeding or otherwise petition the Commission or any court of competent jurisdiction to require either CSP or OPCO, or both, to provide generation service under any established rate schedule of either CSP or OPCO or at a rate lower than such schedules without the express written consent of AEP Ohio.

7) For the period January 1, 2007 through December 31, 2008, Ormet will pay $43 per megawatt-hour for generation service. This price is agreed upon based on Ormet's representations that after a brief ramp-up period it will operate at a full load of approximately 520 MW at a 99% load factor. In addition, Ormet will pay tariff rates and all applicable riders to AEP Ohio for transmission and distribution service. Such tariff rates and riders will be equivalent to OPCO's Schedule GS-4 for one-half (50%) of Ormet's load and CSP's Schedule GS-4 for one-half (50%) of Ormet's load. A list of the currently existing tariff rate components and riders,

and their location in CSP's and OPCO's Commission-approved tariffs, is attached *to this Stipulation as Attachment II. In addition, to the extent required by law,* Ormet will self assess the Ohio kWh tax.

8) The Contract will not be transferable by Ormet to any other party without the consent of AEP Ohio. In the event of a change in control of Ormet, and assuming the continued operation of the Hannibal facilities, Ormet agrees that it will maintain substantially the same level of operations (approximately 520 MW at a 99% load factor), employment (approximately 1,000) and local purchasing practices (about $15,000,000 to $18,000,000 per year in the Monroe County area).

9) Ormet will provide AEP Ohio a deposit equivalent to 130% of the anticipated monthly billing for Ormet's Hannibal facilities at full operation. During the ramp-up period which is expected to occur after Ormet reopens its Hannibal facilities, not to exceed six (6) months, Ormet shall provide a deposit equivalent to 130% of the anticipated next month's billing for the Hannibal facilities. The generation- and transmission-related portion of the deposit will be refunded to Ormet upon Ormet's election to take generation and transmission service from another electric supplier after December 31, 2008, provided that Ormet does not have any outstanding balance with AEP Ohio. Ormet agrees to immediately reestablish a deposit equivalent to 130% of the anticipated monthly generation- and transmission-related billing for the Hannibal facilities at full operation should Ormet return from such other electric supplier to once again take generation- and transmission-related service from either CSP or OPCO, or both. All deposits under this Stipulation shall be made by Electronic Funds Transfer not later than

five (5) business days before the beginning of the next month. Should Ormet fail to provide its deposit in accordance with these terms, Ormet agrees that AEP Ohio has the unilateral right to disconnect service to Ormet three (3) days after providing written notice of disconnect to Ormet. This provision shall remain in effect for so long as Ormet takes any service from either CSP or OPCO, or both.

10) Ormet will prepay, by Electronic Funds Transfer, its monthly bill for generation, transmission, and distribution service by making payments three (3) business days prior to the start of each month (December 27, 2006 for the first service month of January 2007) and prior to the 15^{th} of each month in an amount equivalent to one-half (50%) of the anticipated billing for that month for the Hannibal facilities. Except for during the ramp-up period, the anticipated monthly billing will be based upon full operation. Should Ormet fail to make a payment within two (2) business days of when it is due, Ormet agrees that AEP Ohio has the unilateral right to disconnect service to Ormet three (3) days after providing written notice of disconnect to Ormet. This provision shall remain in effect for so long as Ormet takes any service from either CSP or OPCO, or both.

11) AEP Ohio will make a filing prior to the start of 2007 which will set a market rate for generation service to Ormet's Hannibal facilities for 2007. AEP Ohio will make a filing prior to the start of 2008 which will set a market rate for generation service to Ormet's Hannibal, Ohio facilities for 2008. Such market rate, which will be subject to the Commission's review, shall reflect all generation-related services, including, but not limited to the market for capacity, energy (on-peak

and off-peak), losses to the metering point and load following to meet the requirements of Ormet's Hannibal facilities.

12) For the purpose of compensating AEP Ohio for the differential between service at the market rate established by AEP Ohio's filings under Paragraph 11 and the $43 per megawatt-hour charge for generation service under Paragraph 7, AEP Ohio will be permitted to amortize to income, in the amount of such differential, without reducing rates, their Ohio Franchise Tax phase-out regulatory liability, totaling $56,968,000.

13) In the event that the amortization of the Ohio Franchise Tax phase-out regulatory liability does not fully compensate AEP Ohio for the differential between service at the market rate established by AEP Ohio's filings under Paragraph 11 and the $43 per megawatt-hour charge for generation service under Paragraph 7, AEP Ohio will be permitted to recover that differential under the "Additional 4%" provision of the current Rate Stabilization Plan. See Section 3, pages 8 and 9 of AEP Ohio's February 9, 2004 application in Commission Case No. 04-169-EL-UNC. In the event that AEP Ohio recovers the entire differential between service at the market rate established by AEP Ohio's filings under Paragraph 11 and the $43 per megawatt-hour charge for generation service under Paragraph 7, without having to amortize the entire Ohio Franchise Tax phase-out regulatory liability, AEP Ohio will retain the unamortized portion on its books and the treatment of that balance will be determined by the Commission in AEP Ohio's next base rate proceeding. AEP Ohio's recovery of the differential through either the amortization of the Ohio Franchise Tax phase-out regulatory liability and, if

necessary, the "Additional 4%" provision will be accomplished in a manner which matches the projected differential and the recovery in the same accounting period.

14) In the event Ormet files a petition for relief under the Bankruptcy Code or an involuntary petition for relief under Bankruptcy Code is filed against Ormet, Ormet acknowledges and agrees that:

a. The payment arrangement specified in Paragraph 10 above, with payments made in advance of usage will remain in effect as specified in this Stipulation.

b. Ormet will not file a pleading with the applicable bankruptcy court that seeks to limit or avoid its obligation under the deposit or advance payment provisions of this Stipulation. See Paragraphs 9 and 10 above, respectively.

c. Ormet further agrees that in the event of a bankruptcy AEP Ohio has the first claim on any deposit held under this Stipulation for any amounts owed and any future costs to be incurred as result of AEP Ohio's service to Ormet.

In the event that the bankruptcy court does not permit the provisions of either Paragraph 14 a., b., or c. to be implemented, Ormet will provide AEP Ohio, within twenty (20) days of the petition date, with a post-petition security deposit, as adequate assurance under § 366 of the United States Bankruptcy Code (11 U.S.C. § 366), in the amount equivalent to 130% of the anticipated monthly billing for the plant at full operation.

15) All necessary waivers of Commission rules shall be considered granted by the Commission's adoption of this Stipulation.

16) SCP will withdraw its Notice of Appeal in Supreme Court Of Ohio Case No. 06-1866 after the Commission adoption of the Stipulation and the later of the time for administrative or appellate review of the Commission's order adopting the Stipulation has expired or, if such review is pursued, such review is completed.

17) Upon the Commission's adoption of the Stipulation, CSP, OPCO and SCP will submit to the Commission modified territorial maps consistent with the provisions of this Stipulation.

18) Since the Signatory Parties are waiving their rights to appeal the factual and legal conclusions contained in the June 14, 2006 Opinion and Order, they agree to not rely on such conclusions in any future proceeding. Further, the Signatory Parties urge the Commission to indicate in its order adopting this Stipulation that such conclusions were unique to the facts and circumstances in this proceeding and do not provide any precedent for any future proceeding.

Nothing in this Stipulation shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of any Signatory Party.

No Signatory Party will challenge or directly or indirectly support any challenge to the reasonableness or lawfulness of the provisions of this Stipulation.

This Stipulation is submitted for purposes of this proceeding only, and is not deemed binding in any other proceeding, except as expressly provided herein, nor is it to be offered or relied upon in any other proceedings, except as necessary to enforce the terms of this Stipulation.

In fact, none of the Signatory parties have submitted the entirety of the case they would have otherwise filed or will file if this Stipulation is rejected.

The agreement of the Signatory Parties reflected in this document is expressly conditioned upon its acceptance in its entirety and without alteration by the Commission.

The Signatory Parties agree that:

A. if the Commission rejects all or any part of this Stipulation, or otherwise materially modifies its terms, any adversely affected Signatory Party shall have the right, within thirty (30) days of the Commission's order, either to file an application for rehearing or to terminate and withdraw from the Stipulation by filing a notice with the Commission;

B. if an application for rehearing is filed, and if the Commission does not, on rehearing, accept the Stipulation without material modification, any Signatory Party may terminate and withdraw from the Stipulation by filing a notice with the Commission within ten (10) business days of the Commission's order or entry on rehearing; and

C. if any portion of this Stipulation is found by a reviewing Court to be unlawful, or if any law is enacted which prohibits the continued application of any term of this Stipulation, any Signatory Party adversely affected by any such judicial decision or statutory enactment may withdraw its support for this Stipulation by filing a notice to that effect with the Commission within thirty (30) days of such judicial decision becoming final or such law becoming effective.

If a Signatory Party pursues any action provided for in parts A, B or C above, a hearing shall go forward, and the parties shall be afforded the opportunity to present evidence through witnesses, to cross-examine all witnesses, to present rebuttal testimony, and to file briefs on all issues and pursue all remedies available in a court of competent jurisdiction.

The Signatory Parties agree and intend to support the reasonableness and legality of this Stipulation before the Commission, and in any appeal from the Commission's adoption and/or enforcement of this Stipulation.

IN WITNESS WHEREOF, this Stipulation and Recommendation has been agreed to as of this 20th day of October, 2006. The undersigned parties respectfully request the Commission to issue an Opinion and Order approving and adopting this Stipulation.

Ohio Power Company

Columbus Southern Power Company

Ormet Primary Aluminum Corporation and
Ormet Aluminum Mill Products Corporation

South Central Power Company

Staff of the Public Utilities Commission of Ohio

Ohio Energy Group

United Steel, Paper and Forestry,
Rubber, Manufacturing, Energy, Allied Industrial and
Service Workers International Union

This Contract entered into this __ day of October 2006, by and between Columbus Southern Power Company and Ohio Power Company, hereafter called AEP Ohio, and Ormet Primary Aluminum Corporation, 1233 Main Street, Wheeling, West Virginia 26003, hereafter called the Customer,

Witnesseth:

For and in consideration of the mutual covenants and agreements hereinafter contained, the parties hereto agree with each other as follows:

AEP Ohio agrees to furnish to the Customer, during the term of this Contract, and the Customer agrees to take from AEP Ohio, subject to AEP Ohio's standard Terms and Conditions of Service as regularly filed with the Public Utilities Commission of Ohio (Commission) and the terms and conditions as set forth in the Stipulation and Recommendation in Case No. 05-1057-EL-CSS as approved by the Commission which is attached hereto and hereby made a part of this Contract, all the electric energy of the character specified herein that shall be purchased by the Customer in the premises located at the Customer's Hannibal, Ohio facilities. In the event the regularly filed Terms and Conditions of Service conflict with the terms and conditions set forth in the Stipulation and Recommendation, the latter terms and conditions will be controlling.

AEP Ohio is to furnish and the Customer is to take electric energy under the terms of this Contract for a period of up to 24 months from the time such service is commenced and ending at midnight on December 31, 2008. The date that service shall be deemed to have commenced under this Contract shall be the later of January 1, 2007 or the effective date of the Stipulation in Case No. 05-1057-EL-CSS.

The electric energy delivered hereunder shall be alternating current at approximately 138,000 volts, 3-wire, 3-phase and it shall be delivered at the interconnection of AEP Ohio's two double-circuit 138-kV steel tower transmission lines with the Customer's two double-circuit 138-kV steel tower transmission lines (i.e. in Ohio Township, Monroe County, Ohio at Tower 39 on double circuit Line #1 and at Tower 38 on double circuit Line #2), which shall constitute the point of delivery under this Contract. The said electric energy shall be delivered at reasonably close maintenance to constant potential and frequency, and it shall be measured by a meter or meters owned and installed by AEP Ohio and located at the Kammer Substation.

The Customer's contract capacity is hereby fixed at 520,000 kW/kVA. Beginning July 1, 2007, the minimum billing demand for this Contract shall be 312,000 kW/kVA.

There are no unwritten understandings or agreements relating to the service herein above provided. This Contract shall be in full force and effect when signed by the authorized representatives of the parties hereto, subject to the approval of the Public Utilities Commission of Ohio in Case No. 05-1057-EL-CSS.

The Customer agrees that its electrical facilities shall not be interconnected with any facilities other than AEP Ohio's facilities unless written authorization is received from AEP Ohio.

Columbus Southern Power Company
Ohio Power Company

By:______________________________
(Signature)

____
(Printed Name)
Title:______________________________

Date:______________________________

Ormet Primary Aluminum Corporation

By:______________________________
(Signature)

____
(Printed Name)
Title:______________________________

Date:______________________________

Attachment 2

	Sheet No.	
Tariff Rate or Rider	CSP	OPCo
Customer Charge	24-1	24-1
Demand Charge	24-1	24-1
Reactive Demand Charge		24-1
Universal Service Fund Rider	60-1	60-1
Energy Efficiency Fund Rider	61-1	61-1
kWh Tax Rider	62-1	62-1
Gross Receipts Tax Credit Rider	63-1	63-1
Municipal Income Tax Rider	65-1	65-1
Franchise Tax Rider	66-1	66-1
Regulatory Asset Charge Rider	67-1	67-1
Provider of Last Resort Charge Rider	69-1	69-1
Monongahela Power Litigation Termination Rider	73-1	
Transmission Cost Recovery Rider	75-1	75-1
Major Storm Cost Recovery Rider	77-1	77-1

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Complaint of Ormet Primary Aluminum Corporation and Ormet Aluminum Mill Products Corporation,	)	
Complainants,	)	Case No. 05-1057-EL-CSS
v.	)	
South Central Power Company and Ohio Power Company,	)	
Respondents.	)	

SUPPLEMENTAL OPINION AND ORDER

The Commission, considering the complaint, the evidence of record, the arguments of the parties, and the applicable law, and being otherwise duly advised, hereby issues this supplemental opinion and order.

APPEARANCES:

Dinsmore & Shohl LLP, by John E. Selent and Edward T. Depp, 1400 PNC Plaza, 500 West Jefferson St., Louisville, Kentucky 40202, and Brian S. Sullivan, 255 E. 5th St., Suite 1900, Cincinnati, Ohio 45202, on behalf of Ormet Primary Aluminum Corporation and Ormet Aluminum Mill Products Corporation.

Thompson Hine LLP, by Robert P. Mone, William R. Case, Thomas E. Lodge, Kurt P. Helfrich and Carolyn S. Flahive, 10 W. Broad St., Suite 700, Columbus, Ohio 43215-3435, on behalf of South Central Power Company.

Marvin I. Resnik, American Electric Power Service Corporation, 1 Riverside Plaza, 29th Floor, Columbus, Ohio 43215, on behalf of Ohio Power Company.

McNees, Wallace & Nurick, LLC, by Samuel C. Randazzo, Lisa G. McAlister and Daniel J. Neilsen, 21 East State Street, Columbus, Ohio 43215, on behalf of Industrial Energy Users-Ohio.

Nathaniel Hawthorne, 27600 Chagrin Boulevard, Suite 260, Cleveland, Ohio 44122, on behalf of the United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union.

Boehm, Kurtz & Lowery, by David F. Boehm and Michael L. Kurtz, 36 East Seventh Street, Suite 1510, Cincinnati, Ohio 45202, on behalf of Ohio Energy Group.

Jim Petro, Attorney General of the State of Ohio, by Duane W. Luckey, Senior Deputy Attorney General, by Thomas W. McNamee and William Wright, Assistant Attorneys General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Janine L. Migden-Ostrander, Ohio Consumers' Counsel, by Jeffrey L. Small, Assistant Consumers' Counsel, Office of Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215, on behalf of the residential consumers of Columbus Southern Power Company and Ohio Power Company.

OPINION:

I. History Of This Proceeding

On November 14, 1996, in Case Nos. 96-999-EL-AEC and 96-1000-EL-PEB, the Commission approved a joint petition by Ohio Power Company (Ohio Power) and South Central Power Company (South Central) to reallocate their service territories such that, effective December 31, 1999, all of the facilities of Ormet Primary Aluminum Corporation and its affiliates in Hannibal, Ohio (Hannibal Facilities) were reallocated to South Central's service territory. In the Finding and Order, the Commission also approved an Interim Agreement and a Curtailment and Indemnity Agreement between Ohio Power and Ormet Primary Aluminum Corporation.

In addition, Ormet Primary Aluminum Corporation and South Central executed an "Agreement for Electric Service," (Service Agreement) which provided for the sale of a maximum of 20 MW of electric power and energy to Ormet Primary Aluminum Corporation from South Central (Joint Ex. 1 at 5). Under this arrangement, Ormet would obtain the remaining electricity to serve the Hannibal Facilities' load from the market (Joint Ex. 1 at 4). This agreement was amended effective January 1, 2004, with the execution of the "First Amendment to and Modification of Agreement for Electric Service" (First Amendment) in which South Central and Ormet Primary Aluminum Corporation agreed to terminate in total any obligation of Ormet to buy, and of South Central to sell to Ormet, electric power and energy (Joint Ex. 1 at 5-6).

Subsequent to the execution of the First Amendment, Ormet Primary Aluminum Corporation and Ormet Aluminum Mill Products Corporation (Ormet) filed for Chapter 11 bankruptcy protection in the Untied States Bankruptcy Court (Joint Ex. 1 at 6). On January 25, 2005, Ormet curtailed operations at the Hannibal Facilities. Operations at the facilities have not been restarted (Joint Ex. 1 at 7).

On August 25, 2005, Ormet filed a petition to transfer rights to furnish electric service and/or reallocate certified electric service territories, a complaint for inadequate service against South Central and a complaint for unjust, unreasonable and discriminatory proposed rates against Ohio Power. This pleading requests that the Commission: transfer South Central's rights to serve Ormet's facilities to Ohio Power or reallocate the service territories of Ohio Power and South Central such that all of Ormet's facilities are part of Ohio Power's certified territory; and order Ohio Power to serve Ormet, upon such transfer or reallocation, at rates in accordance with Ohio Power's unbundled standard tariff GS-4 rate schedule.[1]

Ohio Power and South Central both filed answers to the complaint on September 20, 2005. In addition, South Central and Ohio Power filed motions to dismiss the complaint on September 20, 2005. The motions to dismiss were denied by the attorney examiner on October 27, 2005.

Section 4933.83(B), Revised Code, provides for a two-step process under which: (1) the Commission must find that an electric supplier has failed to provide, or propose to provide, physically adequate service and order that such failure be corrected within a reasonable time; and (2) if such electric supplier fails to comply with the Commission's order, the Commission may authorize another supplier to serve and shall amend the certified territories of the respective electric suppliers. Therefore, on February 14, 2006, the Commission held an evidentiary hearing to determine whether South Central provided, or proposed to provide, physically adequate service to Ormet.

On June 14, 2006, the Commission issued its Opinion and Order. In the Opinion and Order, the Commission determined that South Central did not provide, or propose to provide, physically adequate service and the Commission ordered further hearings in this proceeding regarding whether the failure to propose to provide physically adequate service had been corrected by South Central and whether the Commission should authorize another supplier to serve or should order such other remedy authorized by law.

On July 14, 2006, South Central and Ohio Power each filed applications for rehearing. On August 9, 2006, the Commission issued its Entry on Rehearing, denying the

[1] On November 29, 2005, after the commencement of Case No. 05-1057-EL-CSS, Ormet filed motions to reopen Case Nos. 96-999-EL-AEC and 96-1000-EL-PEB and to transfer its facilities back to the certified territory of Ohio Power. The Commission denied Ormet's motions to reopen Case Nos. 96-999-EL-AEC and 96-1000-EL-PEB and to transfer its facilities back to the certified territory of Ohio Power in its June 14, 2006 Opinion and Order.

applications for rehearing filed by South Central and Ohio Power. On August 25, 2006, South Central filed an application for further rehearing, which was denied on September 13, 2006.

On October 5, 2006, the evidentiary hearing in this matter was held pursuant to the Commission's June 14, 2006, Opinion and Order. However, on October 20, 2006, Ohio Power, Columbus Southern Power Company (Columbus Southern Power), Ormet, South Central, Ohio Energy Group (OEG), United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union (USW) and the Commission Staff filed a stipulation (Stipulation) to resolve all issues in this proceeding (Joint Ex. 2). The hearing continued on October 26, 2006, at which time Ohio Power and Columbus Southern Power presented a witness supporting the Stipulation. No party to this proceeding opposed the adoption of the Stipulation by the Commission.

II. Summary of the Stipulation.

The Stipulation was intended by the signatory parties to resolve all outstanding issues in this proceeding. The Stipulation includes, *inter alia*, the following provisions:

1) The Stipulation should be considered as a joint petition, submitted by Ohio Power, Columbus Southern Power, and South Central pursuant to Section 4933.83, Revised Code, to reallocate the service territories of Ohio Power, Columbus Southern Power and South Central such that Ormet's Hannibal Facilities will be located in a joint Columbus Southern Power/Ohio Power service territory effective January 1, 2007. South Central Power shall have no obligation to provide electric service to the Hannibal Facilities, except that South Central Power shall retain its service obligation prior to, on and after January 1, 2007, with respect to three facilities enumerated in the Stipulation.

2) As part of the Stipulation, Ormet has entered into an electric services contract with Ohio Power and Columbus Southern Power. The contract will not be transferable by Ormet to any other party without the consent of Columbus Southern Power and Ohio Power (AEP Ohio).

3) Generation, transmission and distribution service will be supplied by AEP Ohio. Such services will meet Ormet's peak demand of approximately 520 MW at a 99 percent load factor. AEP Ohio's generation service will be supplied only for consumption at Ormet's Hannibal Facilities and will not be resold or transferred by Ormet.

4) Ormet shall not switch to service from a competitive retail electric service provider prior to January 1, 2009. Ormet cannot initiate any proceeding to require either Columbus Southern Power or Ohio Power, or both, to provide

generation service under any established rate schedule of either Columbus Southern Power or Ohio Power or at a rate lower than such scheduled without the express written consent of AEP Ohio.

5) For the period between January 1, 2007 and December 31, 2008, Ormet will pay $43 per megawatt-hour for generation service. In addition, Ormet will pay tariff rates and all applicable riders to AEP Ohio for transmission and distribution service. Such tariff rates and riders will be equivalent to Ohio Power's Schedule GS-4 for one-half (50 percent) of Ormet's load and Columbus Southern Power's Schedule GS-4 for one-half (50 percent) of Ormet's load.

6) Ormet will provide AEP Ohio a deposit equivalent to 130 percent of the anticipated monthly billing for the Hannibal Facilities at full operation.

7) Ormet will prepay, by electronic funds transfer, its monthly bill for generation, transmission and distribution services by making payments three business days prior to the start of each month and prior to the 15th of each month in an amount equivalent to one-half (50 percent) of the anticipated monthly billing for that month for the Hannibal Facilities. Should Ormet fail to make payment within two business days of when it is due, Ormet agrees that AEP Ohio shall have the unilateral right to disconnect service to Ormet three days after providing written notice of disconnect to Ormet.

8) AEP Ohio will make a filing, prior to the start of 2007, which will set a market rate for generation service to Ormet's Hannibal Facilities for 2007. Further, AEP Ohio will make a filing prior to the start of 2008 which will set a market rate for generation service to Ormet's Hannibal Facilities for 2008. Such market rate should reflect all generation-related services and will be subject to the Commission's review.

9) For the purpose of compensating AEP Ohio for the differential between service at the market rate and the $43 per megawatt-hour charge for generation service provided for under the Stipulation, AEP Ohio will be permitted to amortize to income, in the amount of such differential, without reducing rates, their Ohio Franchise Tax phase-out regulatory liability, totaling $56,968,000.

10) In the event that the amortization of the Ohio Franchise Tax phase-out regulatory liability does not fully compensate AEP Ohio for the differential between service at the market rate and the $43 per megawatt-hour charge for generation service provided for under the Stipulation, AEP Ohio will be

permitted to recover that differential under the "Additional 4%" provision of the current rate stabilization plan, Case No. 04-169-EL-UNC.

III. Intervention.

The Stipulation provides that Columbus Southern Power be permitted to intervene in this proceeding. Under the terms of the Stipulation, the Hannibal Facilities would be located in a joint Columbus Southern Power/Ohio Power service territory and Columbus Southern Power will provide one half of the generation service to the Hannibal Facilities. Therefore, the Commission finds that Columbus Southern Power should be permitted to intervene in this proceeding.

Further, on October 26, 2006, the Ohio Consumers Counsel (OCC) filed a motion to intervene in the proceeding. No party to the proceeding opposed the motion to intervene. In the motion to intervene, OCC notes that a motion to intervene, even when submitted out of time, may be granted under "extraordinary circumstances." At the hearing, OCC stated that it does not oppose the Stipulation and that its interest in this proceeding lies in the implementation of the Stipulation in subsequent proceedings. Therefore, the Commissions finds that OCC's intervention will not unduly delay proceedings or unjustly prejudice any existing party. OCC's motion to intervene should be granted.

VI. Evaluation of the Stipulation.

Rule 4901-1-30, Ohio Administrative Code, authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such agreements are accorded substantial weight. *See Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio State 3d 123, 125 (1992), *citing Akron v. Pub. Util. Comm.*, 55 Ohio St. 2d 155 (1978). This concept is particularly valid where the stipulation is supported or unopposed by the vast majority of parties in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. *See, e.g., Dominion Retail v. Dayton Power and Light*, Case Nos., 03-2405-EL-CSS et al., Opinion and Order (February 9, 2005); *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR, Order on Remand (April 14, 1994); *Ohio Edison Co.*, Case Nos. 91-698-EL-FOR et al., Opinion and Order (December 30,1993); *Cleveland Electric Illum. Co.*, Case No. 88-179-EL-AIR, Opinion and Order (January 31, 1989). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St. 3d 547 (1997)(*quoting Consumers' Counsel, supra*, at 126). The Court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission.

(1) <u>Is the settlement a product of serious bargaining among capable, knowledgeable parties?</u>

In considering whether there was serious bargaining among capable and knowledgeable parties, the Commission evaluates the level of negotiations that appear to have occurred and takes notice of the experience and sophistication of the negotiating parties. In this case, it is clear from the record that all parties, at the time the Stipulation was filed, participated in negotiations. The signatory parties routinely participate in complex cases before the Commission and are represented by counsel who practice before the Commission on a regular basis. Moreover, the signatory parties represent a diversity of interests including the utility and industrial consumers as well as the Commission Staff (Joint Ex. 2 at 2). Therefore, the Commission finds that the first prong of the test is met by the Stipulation.

(2) <u>Does the settlement, as a package, benefit ratepayers and the public interest?</u>

The Stipulation fully resolves the complex legal issues raised by Ormet in its petition filed on August 25, 2005. Further, the record in this case demonstrates that their Hannibal Facilities, when fully operating, employ approximately 1,000 people with total annual wages of $40,000,000 and health care benefits costing over $10,000,000 per year. In addition, Ormet pays approximately $1,000,000 annually in taxes to Monroe County, Ohio and its school district (Joint Ex. 2 at 4). These extensive economic benefits can only be obtained through the resumption of operations at the Hannibal Facilities, and the Stipulation will facilitate the resumption of those operations. Therefore, upon careful consideration of the record in this proceeding, the Commission finds that the stipulation, as a package, benefits ratepayers and the public interest.

modest production growth in the United States and western Europe

In the United States and western Europe, new contracts for the supply of power will allow three smelters with a combined capacity of around 490 000 tonnes to be restarted in 2007. However, growth in aluminium capacity in Europe and the United States is expected to be constrained over the medium term as relatively higher energy costs and aging technology reduce the profitability of aluminium production.

new smelters in Iceland, the Russian Federation and the Middle East

Over the medium term, the development of new aluminium capacity will occur largely in countries where companies can secure long term, competitive power contracts. Reflecting this, a number of aluminium producers are moving production to areas that have access to relatively low cost energy, such as the Russian Federation, Iceland and the Middle East. A common feature among these projects is the concurrent development of integrated electricity generation facilities. The Russian Federation and Iceland have considerable low cost hydroelectric power sources (Iceland also has geothermal power) that can be

aluminium smelting technology

Aluminium is produced by dissolving alumina in a molten liquid cryolite solution (at around 1000°C) in large steel furnaces (pots) lined with refractory bricks and containing carbon cathodes and anodes. These furnaces become electric cells when an electric current is passed through the cryolite from a carbon anode (positive electrode) to a carbon cathode (negative electrode). The electrolytic reaction reduces alumina to aluminium.

The production of aluminium is extremely energy intensive, requiring around 15 megawatts of power to produce one tonne of aluminium. Electricity typically accounts for around a third of the total cost of producing aluminium. Reflecting this, significant research is being conducted to find methods that will reduce the use of electricity and hence the marginal cost of producing aluminium.

use of ionic liquids

Current production processes require a substantial amount of electricity to ensure that the temperature in the furnace is high enough to keep the cryolite in liquid form. The use of ionic liquids may reduce the amount of electricity used in aluminium smelting. Ionic liquids (a form of molten salt) typically melt at temperatures below 100°C, and as such require a lower temperature to remain in liquid form. If ionic liquids can be substituted for cryolite, the energy needs of a smelter could be reduced dramatically. Current research indicates that the use of ionic liquids may reduce the electricity used in aluminium production by 20-30 per cent.

drained cathode cell technology

The use of electricity in the production of aluminium can also be reduced by minimising the distance between the cathode and the anode in the cell. With a smaller distance to travel through the cryolite solution, electrical resistance and hence energy consumption can be reduced. However, if the distance is too small, the strong magnetic fields in the cell can cause waves in the pool of molten aluminium. If the liquid aluminium makes contact with an anode, it can form a short circuit or cause the solution to reoxidise which reduces aluminium production. Drained cathode cells can be used to prevent this problem.

Drained cathode cells have a titanium diboride/carbon composite coating. Titanium diboride has high electrical conductivity, low solubility in aluminium and cryolite and can be wetted by aluminium, which avoids the problem of short circuits and reoxidation. Research indicates that this technology has the potential to increase the life of cells and reduce electricity use by at least 10 per cent.

used to provide relatively low cost base load electricity to planned additions to aluminium smelting capacity.

In Iceland, additional capacity is expected to come from Alcoa's Fjardaal smelter (344 000 tonnes a year) and Nordural's Grundartangi smelter expansion (40 000 tonnes a year) as they ramp up to full production after scheduled commissioning in mid to late 2007. In addition, Alcan's ISAL smelter expansion (280 000 tonnes a year) is expected to be commissioned in 2010.

In the Russian Federation, aluminium production is expected to increase significantly. Rusal, the Russian Federation's largest aluminium producer, has announced plans to increase total production to 5 million tonnes of aluminium by 2013 (from 2.7 million tonnes in 2005). Rusal's additional capacity is expected to come from upgrades to existing smelters and the commissioning of new smelters in the Krasnoyarsk and Irkutsk regions (both 600 000 tonnes a year) in 2009 and 2010 respectively.

The Middle East is also expected to contribute significantly to growth in aluminium capacity over the outlook period. The region has abundant, relatively low cost natural gas and oil resources that facilitate the development of electricity generation facilities that are integrated with new smelter projects. One example is Ma'aden's Az Zabirah Aluminium Project (620 000 tonnes a year) in Saudi Arabia that is being developed concurrently with an oil fired 1800 megawatt power station.

In 2006, the Middle East accounted for an estimated 6 per cent of world aluminium production. Over the medium term, combined new capacity approaching 3 million tonnes (see table) is expected to be commissioned, increasing the region's share of world production capacity to around 8 per cent in 2012.

projects to be commissioned in the Middle East over the outlook period

location	company	annual capacity	start	other
Sohar	Alcan, Oman Oil Company and Abu Dhabi Water and Electricity Authority	350 000 tonnes	2008	the smelter will have long term access to a dedicated supply of electricity through the construction of a new 1000 MW power plant, with potential for a second phase expansion to double capacity
Qatar	Hydro Aluminium and Qatar Petroleum	570 000 tonnes	late 2009	the smelter will have a dedicated gas power plant with an installed capacity of 1350 MW
Taweelah, Abu Dhabi	Dubai Aluminium and Mubadala Development Company	700 000 tonnes	phase 1 2010	the project will have an initial capacity of 700 000 tonnes, with the potential to double capacity
Az Zabirah, Saudi Arabia	Ma'aden	620 000 tonnes	2010	power, steam and desalinated water will be provided by a 1800 MW oil fired power station
Arak, Iran	Iralco	130 000 tonnes	2008	addition of number 6 potline will be partially offset by the closure of the first three potlines (net change of 60 000 tonnes)

Australia's export earnings to ease over the medium term

Australia's production of aluminium is forecast to be little changed in 2006-07 as no new smelting capacity is expected to come on line. However, the value of aluminium exports is forecast to increase by 15 per cent to $5.5 billion in 2006-07, reflecting increased export volumes and prices.

Over the medium term, there are no committed expansions to Australia's aluminium production capacity. Studies are currently being conducted into the construction of a fourth potline at both the Portland smelter in Victoria and the Kurri Kurri smelter in New South Wales. In addition, Rusal is considering the construction of a new smelter in Queensland (with a dedicated power station). However, Papua New Guinea has emerged as a potential competitor to Australia for the construction of the new smelter, partly because of its abundant reserves of natural gas and the potential for the development of hydropower. In 2011-12, export earnings in real terms (2006-07 dollars) are projected to decline by around a third from their 2006-07 level to $3.7 billion, largely because of expected lower export prices.

alumina

· kate penney

After reaching a high of US$650 a tonne in early 2006, spot alumina prices declined sharply to around US$200 a tonne in December 2006 as the tight global demand-supply situation eased. Increased world production of alumina (particularly in China, Australia and Brazil) contributed substantially to meeting the burgeoning demand in China in particular. For 2006 as a whole, the spot alumina price declined by an estimated 2 per cent to average US$435 a tonne.

In 2007, the alumina spot price is forecast to average US$236 a tonne, around half what it was in 2006. The lower prices reflect the effects of higher production in China, India and Greece. In China, expansions at Chalco's Pingguo refinery (of 800 000 tonnes a year), Guizhou refinery (400 000 tonnes a year) and Coalmine Alumina Sanmexia Company's refinery (1.2 million tonnes a year) are expected to be completed by mid-2007. In addition, expansions at Mytilineos Holding's Distomo refinery (of 275 000 tonnes a year) in Greece and Hindalco's Muri alumina refinery (of 290 000 tonnes) in India are also expected to be commissioned in 2007.

Declining spot and contract alumina prices have forced a number of refineries to shut-down or reconsider expansion plans (that were made when prices were considerably higher). For example, Ormet's Burnside alumina refinery (800 000 tonnes a year) in the United States and Alcoa's Point Comfort alumina refinery (2.3 million tonnes a year), also in the United States, commenced closure at the end of 2006. An average alumina refinery requires an alumina price of around US$230–240 a tonne to cover operating costs. Any further capacity closures will tend to limit the decline of spot alumina prices.

Over the remainder of the projection period, growth in demand for alumina is expected to remain strong, reflecting expansions to aluminium smelting capacity. In response, alumina capacity expansions are expected to occur in Brazil, China, Guinea and Australia. However, with prices projected to remain close to production costs in the next few years, some refineries may close higher cost capacity or delay expansion plans.

Reflecting these developments, spot alumina prices are projected to increase moderately toward the end of the outlook period, but remain below prices in 2005 and 2006.

In 2012, spot alumina prices in real terms (2007 dollars) are forecast to average US$212 a tonne, less than half what they were in 2006.

output of alumina to increase in Australia

Australia's alumina production is forecast to increase by 6 per cent to around 19 million tonnes in 2006-07, driven largely by the expected completion of the Gove refinery expansion (of 1.8 million tonnes) in the Northern Territory. In 2006-07, Australia's export earnings are forecast to increase by 22 per cent to around $6.4 billion, driven largely by higher export volumes.

Further expansions to Australia's alumina refining capacity are expected over the medium term. BHP Billiton's Worsley Efficiency and Growth project (an expansion of 700 000 tonnes) in Western Australia is expected to begin production in 2010. In addition, CHALCO is considering constructing a 2.1 million tonne refinery in 2011 at an undetermined location in north Queensland to process bauxite from the Aurukun mine. With limited growth in Australia's aluminium production capacity over the outlook period, it is expected that the majority of the projected increase in alumina output will be exported.

Aluminum to Beat Copper as Takeovers Squeeze Supply (Update2)

By Brett Foley and Chanyaporn Chanjaroen

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Enlarge

Porters carry a sheet of aluminum

July 2 (Bloomberg) -- Aluminum, the worst performer on the London Metal Exchange since 2002, has the best chance to advance for at least the next six months.

A growing number of investors say takeovers of Alcan Inc. of Canada and Russia's OAO Sual Group may reduce aluminum production as

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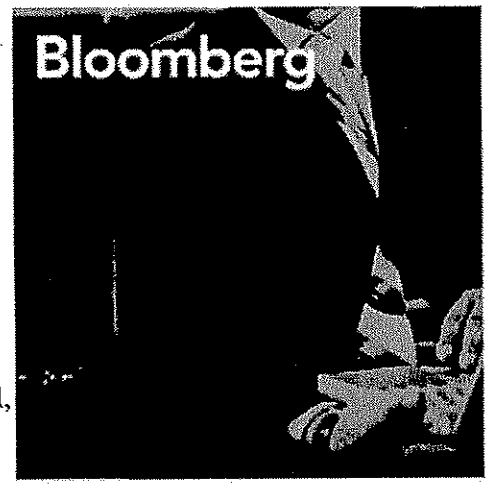
China, the world's largest supplier, cuts exports. Aluminum will be the only metal on the LME to gain for the rest of 2007, while copper, nickel, zinc and tin decline, futures markets show.



United Co. Rusal, the Russian aluminum company controlled by billionaire Oleg Deripaska, expects the metal to appreciate 50 percent to $4,000 a metric ton as early as next year. Prices will probably rise through 2010, say Deutsche Bank AG, UBS AG and JPMorgan Chase & Co., increasing profit for miners BHP Billiton Ltd. and Alcoa Inc. and hurting consumers, such as Boeing Co. and bottlers for Coca-Cola Co.

``Aluminum futures are the best place to park your money,'' says Jon Bergtheil, head of global metals strategy at JPMorgan in London. ``Copper and nickel have more downside potential than aluminum.''

Aluminum for immediate delivery in the so-called cash market is selling for $2,675.80 a metric ton, and futures contracts indicate that prices will reach $2,756 in February. Copper, now at $7,678 a ton, will decline to about $7,350 while nickel will slide from $36,315 to $35,420 on the LME.

Benchmark aluminum for delivery in three months on the LME gained $31, or 1.1 percent, to $2,756 a ton at the close in London today.

`World Will Pay'

Rising energy costs threaten to drive up prices because aluminum production consumes 15 megawatts of power for each ton, equal to 370 euros ($501) for the typical smelter plant in Germany. Power to be delivered in 2010 now sells for 55 euros a megawatt- hour, or 825 euros a ton of aluminum, according to prices from broker GFI. Metals prices will keep pace or manufacturers may shut smelters to save money.

``There hasn't been investment in the industry over the past two decades, and the world will pay the price for that,'' says Jim Rogers, the chairman of New York-based Beeland Interests Inc. and author of ``Hot Commodities.'' ``It has much higher energy costs compared with the other base metals, and as plants are taken off stream because of rising costs, we will see a tightening in supply.''

Aluminum also is buoyed by the prospect of the biggest producers wielding more power than OPEC does in the oil market.

Alcoa's hostile $28 billion bid for Alcan may result in the world's five largest aluminum producers controlling 54 percent of world supply, compared with 43 percent a year ago. By comparison, the 12-member Organization of Petroleum Exporting Countries pumps 41 percent of the world's oil.

Airbus Concern

Alcoa, Rusal, BHP Billiton and the rest of the industry sell about $85 billion of aluminum a year to makers of beer cans, airplanes, window frames and car parts. Higher prices may hurt profits at companies ranging from Pepsi-Cola Bottling Co. to Airbus SAS to Ford Motor Co.

``Alcoa and Alcan getting together, that's probably the key issue for the commodity right now," says Tom Williams, the head of purchasing for Airbus in Toulouse, France. ``We want to be sure that whatever happens we still end up with a sensible competitive environment at the end of it." The average airplane is 80 percent aluminum.

Alcoa wants Montreal-based Alcan so it can expand capacity to meet a doubling of demand by 2020, according to spokesman Kevin Lowery. This year, production will outstrip demand by 576,000 tons, according to CRU, a London-based metals consultant.

`Bring Strength'

The takeover ``will bring the strength of two companies to bear to make sure we can elevate what we do for our customers," says Lowery. Alcoa, based in New York, is prepared to sell assets to resolve antitrust issues, he said.

Aluminum is cheap relative to every other metal on the LME, the result of production in China. The metal has increased on average 14 percent a year for the past five years, compared with 26 percent for tin and 42 percent for lead.

The price of aluminum will rise next year to $3,086 a ton, or $1.40 a pound, up from an earlier forecast of $1.30 a pound, according to Dan Brebner at UBS in London, because of raw material and energy costs. Aluminum has averaged $2,774 a ton so far this year.

``In 2008, it looks like aluminum could outperform the other metals,'' says Brebner, executive director of commodities research.

`Significant' Positions

China's decision on June 19 to rein in production by removing a tax rebate on shipments of aluminum rods and bars may result in the country importing more aluminum than it exports by 2009, said Michael Widmer, head of metals research at Calyon in London.

``That should be a big support for prices,'' he said.

Demand for aluminum in China, which is also the world's largest consumer of the metal, will grow 20 percent this year, outstripping the rise in domestic production, Deutsche Bank AG said in a June 22 report. Investors who followed Deutsche Bank's advice to buy aluminum in April 2005 earned a 49 percent profit in 16 months.

The average person in China uses 10 kilograms of aluminum a year, and the average Russian 5 kilograms, compared with 34 for the typical American and more than 50 for a German, according to Rusal estimates.

Forward Buying

Charts tracking aluminum for delivery 63 months from now show the greatest demand after 2008. The price for the December 2010 contract gained 9.5 percent to $2,410 a ton as of June 22, while the most widely traded three-month contract has lost 1.8 percent during the same period.

``The far forward fund buying is significant,'' says Mo Ahmadzadeh, president of metals trading at Mitsui Bussan Commodities in New York.

Rusal, created this year through the merger of OAO Russian Aluminium, OAO

Sual Group and the alumina unit of Glencore International AG, is anticipating a surge in demand. The company plans to expand three plants and build two more as soon as 2012.

Chief Executive Officer Alexander Bulygin said in March that aluminum may reach $4,000 a ton as early as next year.

Aluminum has a ``very favorable long-term outlook,'' Artem Volynets, Rusal's head of strategy, said in a June 29 interview in which he declined to give a specific forecast. ``We expect to see a very interesting picture when China shifts into the importer position.''

Prices also are helped by a slowdown in smelter construction. Aluminum Corp. of Bahrain is facing a natural gas shortage that may scuttle a plan to increase annual capacity to 1.2 million tons. Alba, as the company is known, is trying to buy gas from Qatar to supply its factory.

``If you look past the next five years, some people see very little downside because they believe there will be less supply and the cost of producing this commodity will only go up,'' says Adam Rowley, an analyst at Macquarie Bank Ltd. in London. Increasing energy demand worldwide means ``there is less need to sell it cheaply to smelters.''

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Last Updated: July 2, 2007 13:51 EDT

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Press Release

Source: Century Aluminum Company

Century Aluminum Reports Second Quarter 2007 Results

Tuesday July 24, 4:00 pm ET

MONTEREY, CA--(MARKET WIRE)--Jul 24, 2007 -- Century Aluminum Company (NasdaqGS:CENX - News) reported a net loss of $60.7 million ($1.77 per basic and diluted share) for the second quarter of 2007. Reported second quarter results were negatively impacted by an after-tax charge of $125.1 million ($3.66 per basic share) for mark-to-market adjustments on forward contracts that do not qualify for cash flow hedge accounting and by a non-cash after-tax charge of $2.0 million ($0.06 per basic share) for the early extinguishment of debt. Quarterly results were positively impacted by a tax benefit of $4.3 million ($0.13 per basic share) related to the increase in the carrying amount of deferred tax assets as a result of a state tax law change. The dilutive effect of the convertible notes, options and service-based awards would reduce basic EPS by $0.13.

In the second quarter of 2006, the company reported net income of $45.8 million ($1.41 per basic share and $1.35 per diluted share), which included an after-tax charge of $19.5 million ($0.60 per basic share and $0.57 per diluted share) for mark-to-market adjustments on forward contracts that do not qualify for cash flow hedge accounting.

Second quarter 2007 highlights included:

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--  Strong operating earnings were generated on revenues of $464.0
    million, which increased 3.7 percent from record levels set in the first
    quarter of 2007.
--  All primary aluminum facilities operated at or above capacity.
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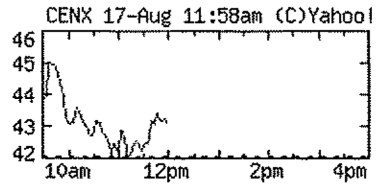

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-- The first cells of the 40,000 tonne expansion of the Grundartangi, Iceland smelter were energized on July 2. The project remains on schedule and budget for a fourth quarter, 2007 completion.
-- Century signed a definitive agreement with Icelandic electric power suppliers Hitaveita Sudurnesja and Orkuveita Reykjavikur for the supply of electrical power to the new aluminum smelter project to be built near Helguvik, Iceland. These contracts provide for the supply of power for approximately 250,000 tonnes of aluminum production.
-- A memorandum of understanding was signed with the Guangxi Investment Group Company to explore the feasibility of developing a project including a high purity aluminum reduction plant and related bauxite and alumina facilities in the Guangxi Zhuang Autonomous Region in China.

Sales in the second quarter of 2007 were $464.0 million, compared with $406.0 million in the second quarter of 2006. Shipments of primary aluminum for the quarter totaled 188,650 tonnes compared with 171,715 tonnes in the year-ago quarter, reflecting the impact of the Grundartangi expansion to 220,000 tonnes, which was completed in the fourth quarter of 2006.

For the first half of 2007, the company reported net income of $3.6 million ($0.11 per basic and $0.10 per diluted share), which includes an after-tax charge of $125.1 million ($3.75 per basic share) for mark-to-market adjustments on forward contracts that do not qualify for cash flow hedge accounting. The dilutive effect of the convertible notes, options and performance shares would reduce basic EPS for the first half of 2007 by $0.24 per share. This result compares with a net loss of $95.8 million ($2.96 per basic and diluted share) in the year-ago period, which included an after-tax charge of $203.0 million ($6.28 per basic share) for mark-to-market adjustments on forward contracts that do not qualify for cash flow hedge accounting. The dilutive effect of the convertible notes, options and service-based awards would reduce basic EPS for the first half of 2006 by $0.14 per share.

Sales in the first six months of 2007 were $911.7 million compared with $752.9 million in the same period of 2006. Shipments of primary aluminum for the first six months of 2007 were 373,272 tonnes compared with 328,666 tonnes for the comparable 2006 period.

"We made important progress on our long-term initiatives during the quarter," said president and chief executive officer Logan W. Kruger. "The continuing expansion of Grundartangi remains on

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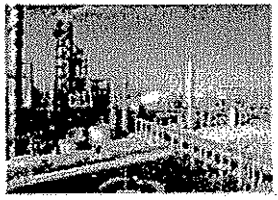

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15 Aug 2007 | London

High aluminium and raw material prices drive up smelter operating costs

available only for purchase

Spiralling aluminium prices, combined with rising raw material costs over the past two years, have pushed primary aluminium smelter operating costs to their highest levels seen in many years.

CRU (http://www.crugroup.com) has recently released its annual Primary Aluminium Smelting Costs report, which details historical, current and forecast costs for the global aluminium industry, with detailed costs for more than 160 smelters, including the 47 largest Chinese smelters. The study is the result of close contacts with aluminium producers and frequent visits to smelters around the world.

The report shows that world average business operating costs at smelters have seen a substantial increase, rising by an average 13% in 2005, on the back of a 15% rise the previous year. Production costs have been escalating due to rising alumina, power and carbon prices, and are seen to continue rising strongly in 2006. The study presents essential reading at this critical point in the aluminium price cycle, and identifies which smelters will have the competitive edge as prices start to fall.

Power costs continue to rise in many regions, forcing the closure of some smelters in Europe, yet the global rise in power costs is kept in check by the introduction of new smelting capacity in lower power cost regions, such as the Middle East and Iceland, or with lower-cost self-generated power capacity in China, India and the CIS. Labour costs also continue to rise globally, however we are seeing a shift in production from high labour cost to low labour cost countries. However, the cost component exhibiting the largest percentage rise on operating costs is carbon, with both carbon raw materials experiencing a significant upward movement.

"Site and Business operating costs should start to fall when metal prices fall, since many power and alumina contracts are metal-linked, and alumina spot prices have now started to fall," said Paul Robinson, Aluminium Business Unit Manager at CRU. "However, industry average conversion costs are unlikely to shift down much from their current high levels, leaving numerous smelters vulnerable when metal prices move back downwards."

CRU's Primary Aluminium Smelting Costs service offers a comprehensive view of the worldwide smelting industry, by providing clear and detailed analysis of the major cost components for individual smelters and their competitiveness regionally and globally. Individual smelter cost profiles list disaggregated cost with a high degree of detail so as to enable readers to make a thorough evaluation of the accuracy of CRU's data. The value-based cost data in the report is derived from CRU's knowledge of smelter operations and its on-going contact with the smelting industry around the world. The report is accompanied by two user models: a highly detailed benchmarking cost model and an analytical time-series cost model. CRU's smelting cost analysis has truly global coverage, covering all primary aluminium smelting capacity around the world.

For details of CRU's 2006 edition of Primary Aluminium Smelting Costs report, click here.

For further details please contact:

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Business Unit Manager - Aluminium

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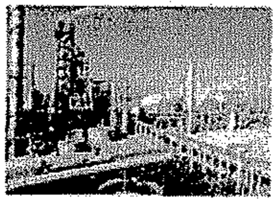

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15 Aug 2007 | London

Primary Aluminium Smelting Costs

2006 Edition

This annual service offers a comprehensive view of the worldwide smelting industry, by providing clear and detailed analysis of the major cost components for individual smelters and their competitiveness regionally and globally. The profiles list individual costs with a high degree of detail so as to enable subscribers to make a thorough evaluation of the accuracy of CRU's data. The cost data in the report is derived from CRU's knowledge of smelter operations and its on-going contact with the smelting industry around the world, using value-based costing methodology. The report is accompanied by two user models: a highly detailed benchmarking cost model and an analytical time-series cost model. CRU's smelting cost analysis is truly global in coverage, determining costs for all primary aluminium smelting capacity around the world.

The summary section of the report provides the historical and forecast data on individual smelters out to the year 2008. It also contains the analysis of individual company and regional averages. CRU's value-based costing methodology ensures that smelters are compared on a conversion cost basis, as well as site costs, business costs, full economic costs, and an avoidable cost basis. This methodology enables readers to distinguish which smelters are most efficient, which are most profitable, which are creating shareholder value, and which are vulnerable to closure.

In addition to the report and the smelter profiles, CRU provides two cost models on CD, including a highly detailed benchmarking model for 2006, and a comprehensive analytical time-series model covering 1990-2016. The models enable subscribers to test the effects of changes in crucial variables, such as metal prices, exchange rates and alumina prices. The models also captures the effect on power costs of "metal-linked" contracts. The ability to manipulate the data is a valuable feature of the service, as is access to the 14 analysts in CRU's Aluminium Group which allows subscribers, whenever they wish, to keep abreast of new developments by telephone, fax and personal visits. CRU is the premier consultancy specialising in the metals and minerals industries worldwide.

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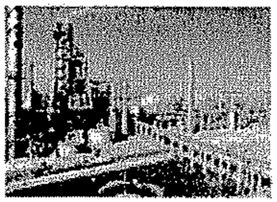

14 Aug 2007 | London

The Long Term Outlook for Aluminium, 2006 Edition

Long-run decisions in the aluminium industry require a long-run view of market conditions, market prices and price risk. These decisions include investment appraisals, valuations for mergers and acquisitions, marking assets to markets, efficient portfolio optimisation, long run capital budgeting and financial planning. In response to this CRU has developed the unique CRU "Compass Model" to provide a robust modelling platform to forecast the long-term aluminium price forecast and the market risks associated with this.

The Compass Model determines the long run attractor price for aluminium smelter investment, around which prices are expected to oscillate. The attractor price allows for a sustainable economic return on capital employed as well as predicting the long term cost by forecasting raw material costs and technological advances. In addition Compass also uses risk analysis techniques to produce probability distributions around the central path. This represents a disciplined, clear and rigorous way of handling uncertainty.

For over 30 years our team of researchers have been recording and tracking the fundamental influences on price, supply/demand and consumption in the aluminium market. The Long Term Outlook for Aluminium Report now draws not only on this knowledge, but also on the capabilities of the Compass Model, to provide uniquely valuable analysis. This service provides a base-line forecast to the year 2030, and covers the following key areas:

Price Forecast – CRU assesses long-term historical aluminium price trends and the long run marginal cost of new smelting capacity in order to determine a plausible range for the long run price of aluminium, with an associated probability distribution.

Consumption Prospects – gives our view on developments in the key end use sectors, including transport, packaging and construction, analysing demand on a market-by-market and country-by-country basis.

Production Prospects – due to our programme of extensive fieldwork and research, associated smelter cost studies and single client undertaking, CRU has built up an extensive database of information on current and potential smelting capacity. We use this to assist us in determining the 'attractor regions' for long-term

The Long Term Outlook for Aluminium is available for £6,500

Please contact Pippa Naish on +44 207 903 2158 for a full list of contents and tables.

only for purchase

smelter investment across the globe.

BRIC economy development – The economies of Brazil, Russia, India and China continue to increase their influence on the long-term development of the aluminium market, either as a driver of consumption or location of new smelter capacity. Our network of contacts and our global presence, with offices in China and South America, allow us to unrivalled insight in to the influence of these economies on our industry.

Smelter Project Profiles – The report also contains over 90 project profiles for aluminium smelters recently constructed, under construction or under consideration. These are contained in a separate profile volume for easy reference.

Independent & Authoritative – CRU remains the largest and longest established, independent metals and mining consultancy. This report is part of an integrated portfolio of products covering all aspects of the aluminium value chain. This depth of understanding and breadth of knowledge allows us to bring you an unrivalled, unbiased and thorough analysis of the industry fundamentals.

Our objectivity allows you to base your analysis on a trusted information source as well as providing the industry with key benchmarks

CRU International is the leading consultancy in the international mining and metals industries. Established over 35 years ago, the company is wholly independent and has a staff of over 180 based in London, Beijing, Santiago, Sydney, Rio de Janeiro and key centres in the United States.

The Aluminium Group provides unrivalled coverage of all aspects of the industry from bauxite through to end-use demand for semis. CRU has extensive experience in forecasting of all major metals, and issues detailed studies of the short, medium and long-term outlook. Our reputation and quality has made us the world's foremost consultancy in the metals industry.

For more information, please contact the Group Manager of the Aluminium Division, Paul Robinson on (+44) 20 7903 2221 or email.

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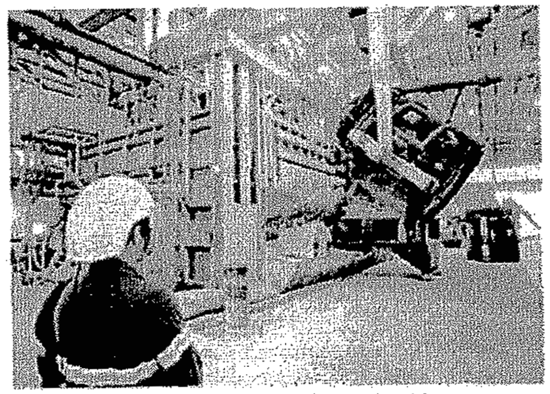
LIGHT METALS

May 2006 National Research Flagship Light Metals

Demand for aluminium to boost alumina exports

Thanks in part to the 2008 Beijing Olympics, China is leading the world in aluminium consumption, with flow-on effects for our alumina production sector. Kate Penney from ABARE (Australian Bureau of Agricultural and Resource Economics) prepared this summary...



Smelter capacity expansion is determined by energy pricing: electricity accounts for an estimated 28% of smelter cash operating costs.

World aluminium consumption is projected to grow at an average annual rate of 4.3% to an estimated 40.7 million tonnes in 2011.

China is expected to be the major driver of growth. Continued population growth and rising per capita incomes are likely to lead to stronger domestic demand for aluminium in cars, consumer durables and construction.

The rate of growth in Chinese aluminium smelting capacity, however, may ease as the Chinese government attempts to rationalise the industry.

With strong consumption growth and slower smelter capacity growth, China is expected to become a significant net importer of aluminium over the medium term.

IN THIS EDITION:

MEET THE SCIENTIST:

Dr Chris Goodes - Theme Leader Aluminium and Magnesium for the Light Metals Flagship and Program Manager for Light Metal Production in CSIRO Minerals.

Alumina capacity expansion

Australia's alumina production and export capacity is projected to increase significantly over the medium-term, reflecting the construction of substantial new alumina refinery capacity, which is now ramping up, committed or in prospect.

Australia's export earnings from alumina are forecast to increase by 22% this financial year. Given the expected expansions to refinery capacity over the medium term, the country's export shipments of alumina are projected to increase by 33% to 19.3 million tonnes in 2010-11.

In the medium-term, world aluminium production growth should slow, reaching an estimated 41.3 million tonnes in 2011.

Generally, capacity expansion is determined by the ability of aluminium smelters to secure competitive power contracts. Electricity accounts for an estimated 28% of smelter cash operating costs.

In developed countries, *where aluminium smelters compete* with industrial and residential users for power, it is becoming more difficult to replace or renew contracts at similar prices.

Therefore, smelter developments planned for the medium term may include integrated power projects, or gravitate toward countries with abundant energy resources such as Iceland and the Middle East.

While there have been studies conducted into expansions at Boyne Island and Gladstone in Queensland, there are no committed expansions in Australia over the medium term.

Aluminium prices are expected to ease as production outpaces consumption and stocks *begin to rise*. *In 2011, real aluminium prices (in* 2006 dollars) are projected to be around 25% lower than in 2005.

Meet Dr Chris Goodes

EARLIER UPDATES

February 2006

November 2005

August 2005

February 2005

October 2004

June 2004

	Unit	2004	2005	2006(f)	2007(z)	2008(z)	2009(z)	2010(z)	2011(z)
World									
Production	'000 tonnes	29 822	31 505	32 884	34 573	36 351	38 226	39 894	41 252
Consumption	'000 tonnes	29 543	31 437	33 006	34 655	36 231	37 732	39 213	40 661
Prices (a)									
- nominal	US$/t	1 716	1 898	2 094	1 945	1 851	1 790	1 713	1 630
- real (b)	US$/t	1 825	1 955	2 094	1 898	1 771	1 679	1 574	1 469
		2003-04	2004-05	2005-06(f)	2006-07(z)	2007-08(z)	2008-09(z)	2009-10(z)	2010-11(z)
Australia									
Production	kt	1 877	1 890	1 930	1 931	1 934	1 938	1 942	1 946
Consumption	kt	318	320	322	331	331	332	333	333
Exports	kt	1 546	1 512	1 637	1 602	1 606	1 609	1 612	1 615

Table: *(a) LME (London Metal Exchange) cash prices for primary aluminium. (b) In 2006 US dollars. (f) ABARE forecast. (z) ABARE projection. Sources: Commodity Research Unit; London Metal Exchange; World Bureau of Metal Statistics; ABARE.* **Click on image to view full scale.**

The **Light Metals Flagship** is a CSIRO initiative and part of the National Research Flagships program that aims to deliver scientific solutions to advance Australia's most important national objectives. One of the largest scientific initiatives ever mounted in Australia, it aligns closely with the Federal Government's **National Research Priorities**. The initiative brings together our national research resources to deliver breakthroughs in fields ranging from healthcare to light metals and the environment.

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CSIRO

DJ UPDATE:Rio:China Aluminum Smelter Expansions Seen Constrained

Last Update: 7:01 AM ET Aug 2, 2007

LONDON, Aug 02, 2007 (Dow Jones Commodities News via Comtex) --
(Updates an item timed at 0946 GMT with additional company comment.)

Aluminum smelter expansions in China are likely to be constrained by a lack of surplus capacity as well as tight raw materials and power supplies, Rio Tinto PLC (RIO.LN) Chief Executive Tom Albanese said Thursday.

"It's no longer clear that China can add smelting capacity in 2007 as it did in 2004," he told an analysts conference call for the company's interim results.

Noting that China's growth in aluminum smelting capacity over the last several years has been absorbed by strong demand, Albanese said consumption is consensually pegged at 30% a year in 2007 and an average 15% for the next five years. "China's (aluminum smelting) capacity utilization rate is running at 90%, so there's little surplus left in the system," he said.

Around 60% of China's raw material needs are imported, Albanese said, either through direct imports of alumina or the import of mined bauxite, which is refined into alumina.

"China has limited bauxite supplies ... and is reliant on imports, particularly from Indonesia," Albanese said, although he noted issues with sustainability of this supply.

With a backdrop of marginal electricity prices as the country's demand for power rises and less is being consumed by more, Albanese said "marginal aluminum smelting costs might rise." He said Chinese production costs support current aluminum prices.

"When smelting hits head on with industrialization, you find that urbanization's use of power pushes smelters away," Albanese said. This creates "more and more of a shift away from incentive pricing," and tests marginal costs against the London Metal Exchange price, he said.

Albanese said stranded power sources are the key to aluminum smelting and said there are very few available globally.

Russia has very strong stranded power supplies, but the lack of available local bauxite and alumina has an impact on marginal costs.

The Gulf region of the Middle East is also a key area for "stranded gas," and both Rio Tinto and Alcan are already "chasing after that," Albanese said. "We hope to be a bigger part of that in the future," although there is regional competition in the Gulf for liquified natural gas, he said.

"Stranded power will be clearer in the future rather than available," he added.

Rio's exposure to aluminum will total some 25% of its earnings once its proposed deal to buy Canada's Alcan Inc (AL) is complete. Rio Tinto currently has aluminum operations in Australia, New Zealand, Sardinia and the U.K.

-By Andrea Hotter, Dow Jones Newswires; +44 (0)20 7842 9413; andrea.hotter@dowjones.com

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(END) Dow Jones Newswires

08-02-07 0700ET

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THE ENAL NEWSLETTER EDITORIAL PAGE

MONDAY, JULY 24, 2006

Uncertainties in the World of Aluminum Investments in Mid-2006

Around 2000-05, the world economy began growing faster than at any time since the post WW2 era. This is mainly a consequence of a general progress towards republican institutions (Rule of Law, Individual Rights, Limited Government, Free Trade) which originated in the 80's. The effect is felt in Latin America (since the 80's), in ex-Communist countries (Central Europe, and now Russia and CIS countries), in China, in India, and now even in Africa although not in all countries and not without some serious tensions.

Economic growth means growth of energy consumption, which means more generating capacity. Building new power plants means facing political objections, the main ones being concerns about environmental impacts, others being more political objections regarding sustainable growth and even objection to so-called "globalization" of economy.

The business world begins to realize that the

PREVIOU

- Of I Que Icel Sib Brit Col Poli Que beh and aro Wo
- Alu ma exc not ene why Inve Dec is s unc
- Sel Equ Knc Sell Wh
- Ber Mo Lith for :
- Sell ma prin sm con oth indu wha hun trav

general resistance to so-called "globalization", meaning in the minds of classical economists resistance to wealth creation through optimization of resources and markets according to the eternal dogma of the Market's "Invisible Hand", happens not because the world opinion is really turning against Adam Smith's famous theories, but because so-called "Capitalism" is seen as degenerating into "Stock-Optionism". Stock-Optionism being the system creating a link between the shutdown of a faraway plant, the anticipated cost reduction supposedly resulting of it, the anticipated increase in profits, and the anticipated increase in stock prices, this in turn benefiting insider trading and stock option holders who can cash in now on these cumulated anticipations. This link has a name: the strategy aiming at stockholders' value creation as a goal in itself, instead of as a consequence of a successful competitive strategy. Whatever can be your opinion about Stock-Optionism, it triggered a resistance to Globalization which impacted on investments in energy capacity whether new capacity or refurbishing.

Energy prices had to go up first to force public opinions to concentrate on the real issues and approve the following measures:

- <!--[if !supportLists]--> <!--[endif]-->The world economy needs to keep growing if underdeveloped countries will achieve a decent living standard; this means more energy generation.
- <!--[if !supportLists]--> <!--[endif]-->Growth can be

sustained with a more optimal use of energy; *various energy savings measures will be* encouraged. Energy consumption per capita, today of 20-50 GigaJoules/Year in developing countries, of 150-200 in Europe and of 350 in North America, should progress to around 150GJ throughout the world. Even such modest goals mean a total generation capacity multiplied by about 4 in 2050.

- <!--[if !supportLists]--> <!--[endif]-->Thermal and nuclear power plants will supply the bulk of new capacity during the next 30 years;

- <!--[if !supportLists]--> <!--[endif]--> CO_2 emissions do impact on global warming, and they must be controlled, eventually eliminated; this will trigger higher energy costs. World emissions reached 7.8 Gigatonnes of carbon in 2002. If nothing is done they will reach 12 Gt by 2030 which may not yet provoke major climate changes, but would mean that unavoidable future growth will lead to such a situation. A reasonable plan in the context of the Kyoto Protocol aims at a peak of 11.5 by 2025, then *a downtrend leading to a figure of 9 Gt by 2050.* Massive reforestation will be pursued, which will both help solve the CO_2 problem (trees and some high-fiber plants consume CO_2 to generate cellulose through the chlorophyllian conversion), help the pulp & paper industry and reclaim soil in arid lands.

- <!--[if !supportLists]--> <!--[endif]-->Natural gas, a noble form of energy that can be and is more and more used as motor fuel as well, generates half less *CO_2 than coal. It is getting cheaper to ship. It will be* favored, but for these very reasons its market prices will increase further.

- <!--[if !supportLists]--> <!--[endif]-->The share of electrical energy in total energy consumed by industry and consumers has been growing and will continue to grow, from 18% in 2002 to around 50% in 2050;
- <!--[if !supportLists]--> <!--[endif]-->Renewable energies (wind, solar, biomass, photovoltaic, others) will take a bigger share in capacity (perhaps 50% in 2050) but conventional energies will keep growing in capacity in absolute terms if only to reach the above goals. They will all represent high-cost energy, even when subsidized; not suitable for aluminum smelting.
- <!--[if !supportLists]--> Consumers and industry must prepare for generally higher energy prices.

On top of that, political considerations impact on energy markets: The Middle-East is part of the Arab World, considered more and more as hostile to the United States, to other "Anglo-Saxon" countries and to many European countries. It also controls some 40% of world oil production, which in theory constitutes a political risk. War situations in the Middle East have, since 1948 onwards, put growing pressure on oil availability and prices. There is a stronger incentive for the US, and also for Japan and Europe, to encourage self sufficiency in energy generation.

Aluminum producers must adapt therefore, not only to a general increase of energy prices and to a gradual vanishing of "Power Islands" offering excess energy at discounted prices, but also to a **higher differential between long term energy costs and energy prices**.

However since aluminum prices and demand are increasing, all this should constitute a generally favorable context for aluminum investment. And it is. Yet, one can wonder why so many large greenfields keep being delayed. One can also wonder why supposedly obsolete Soderbergs are now revamped and extended, when everyone knows that they pollute more and they are less efficient; and why many older, smaller prebakes do the same.

Reasons are:

<!--[if !supportLists]-->a) The bigger the greenfield, the bigger is the 10-year energy contract to negotiate. Energy suppliers do not have excess capacity anymore. They prefer smaller contracts, easier to handle in case of big shifts in demand.

<!--[if !supportLists]-->b) The bigger the greenfield, the more it will be dependent on export sales to faraway destinations of ingots, billets or sows. Also bigger will be the energy lost in casting, then shipping and remelting the metal. That factor was negligible when energy costs were low. Now it is not.

<!--[if !supportLists]-->c) <!--[endif]--> The bigger the greenfield, the higher is the risk

of capital cost over run.

<!--[if !supportLists]-->d) Capital costs per tpy in a revamping or extension are roughly half the ones in any greenfield.

<!--[if !supportLists]-->e) <!--[endif]--> There are more and more opportunities for an older, smaller smelter, to invest in the casthouse to move into high added value semi-products for a local market.

<!--[if !supportLists]-->f) Shifting to Lithium Bath, thus increasing conductivity and reducing temperature, means often the fastest way to increase the bottom line for a minimal investment.

POSTED BY DEENA AT 11:06 AM

0 COMMENTS:

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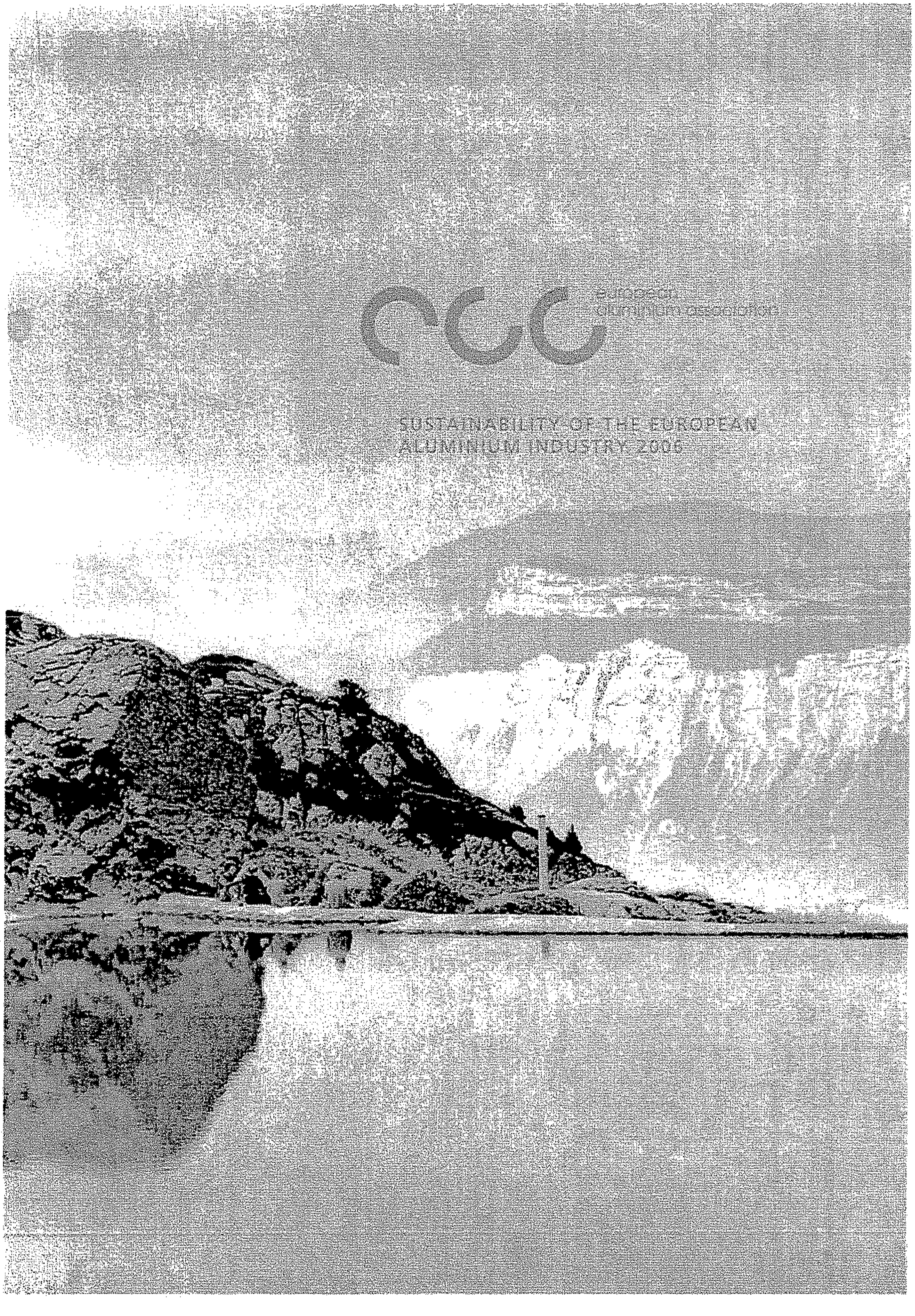
european aluminium association

SUSTAINABILITY OF THE EUROPEAN ALUMINIUM INDUSTRY 2006



INTRODUCTION

European Aluminium – A sustainable industry for future generations

In 2002 the European Aluminium Association (EAA) and its member companies embarked on a pioneering journey towards measuring sustainability. Through the Aluminium for Future Generations programme the European Aluminium Industry, it's partners the Wuppertal Institute for Climate, Environment & Energy; Versailles University and an additional peer group of internal and external stakeholders developed 34 measurable Sustainable Development Indicators (SDI) to be systematically tracked and transparently reported by the European aluminium industry.

Decoupling growth from environmental and social impact is the driving principle behind a successful sustainable development strategy. Progress needs to be benchmarked against a clear and realistic perception of the internal and external business reality. Reliable measurement is essential to guarantee continued monitoring, careful evaluation, committed implementation and tangible results. These are the cornerstone principles behind the European aluminium industry's SDI report.

The first report was issued in 2004 and showed an industry that had significantly improved since 1997. The data clearly showed a committed industry making good progress towards our target of becoming a more sustainable industry. This 2006 report, is the European aluminium industry's second benchmarking exercise and the data show further improvements, such as emissions down, natural resource use down, worker safety up, recycling rates up, worker training up.

This pragmatic and transparent approach has been key in encouraging all levels of the European Aluminium industry, from large integrated companies to small and medium sized companies, to become involved in the survey.

In 2007, the industry will be asking its stakeholders for honest feedback on the progress, the process and the future pathway towards sustainability for the European aluminium industry. As the industry's Mission Statement outlines, continuous improvement is the aim. Input from stakeholders will be actively encouraged to ensure we continue to implement best practices and report the results accurately and transparently.

Of course it is important to consider the European aluminium industry within the larger context, to see the big picture and not only focus on the regional situation. For this reason we also include the competitiveness of the aluminium industry to enable readers to evaluate the aluminium industry's situation in Europe in relation to other regions.

Sustainability is more than just an initiative it is a philosophy that runs right through the industry influencing every activity and decision. The European Aluminium industry is committed to this philosophy and committed to continuous improvement on the pathway to sustainability.

TABLE OF CONTENT

COMPETITIVENESS

SUBSTAINABLE DEVELOPMENT INDICATORS

Aluminium Smelters Cost Report

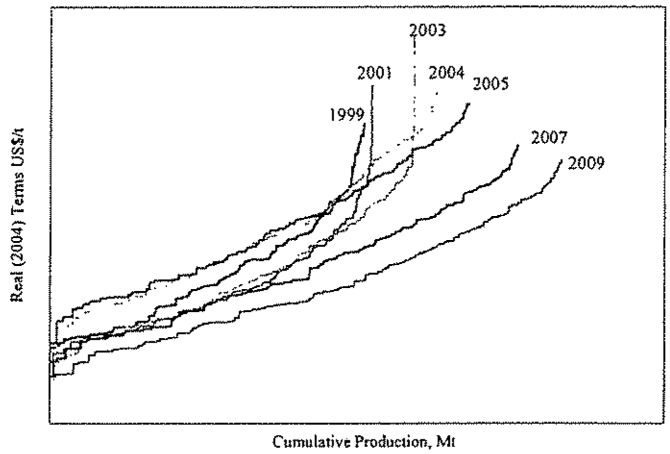
AME's *Aluminium Smelter Costs* report examines and analyses the cost structures of 182 smelters worldwide. Costs in 2004 were well above industry trends, due mainly to a spike in alumina prices affecting particularly those plants that rely on the spot market. These high feedstock prices were ultimately the result of unexpectedly rapid economic growth in China, a phenomenon that also had its impact on some of the other drivers of smelting cost, particularly energy, coke and alumina shipping prices.

Around the world older-style Søderberg anode technology is progressively being replaced by the use of prebaked anodes. This historic change is demanded to improve the working environment and reduce emissions. But there are positive cash cost benefits because the changeover is usually accomplished with a plant expansion, more efficient cells and labour savings.

In recent years, new power supply contracts that deliver less electricity at considerably higher prices have threatened the continued viability of those United States smelters that survived the 2000-01 Pacific North-West power crisis. The devaluation of the US dollar against the currencies of many competing countries has now thrown a lifeline to the US smelting industry.

The past two years have seen a tug-of-war over the pace of smelter development in China. On one side, provincial governments and wealthy entrepreneurs are promoting new smelting projects to capture the country's enormous appetite for aluminium. But the central government is desperate to control the pace of investment, wary not only of the potential waste of capital, but also of the limitations that flow from the country's shortages of the two essential ingredients, alumina and electricity. The report includes analysis of 53 major Chinese smelters and projects. Many of the proposed new plants are associated with the forced closure of small inefficient smelters, but if all were to proceed, the voracious Chinese Dragon would be afflicted by severe indigestion with repercussions throughout the global industry.

Aluminium Cost Trends
1999 - 2009



Smelters and Projects analysed:

Argentina: Aluar
Australia: Aldoga, Bell Bay, Boyne Island, Kurri Kurri, Point Henry, Portland, Tomago
Azerbaijan: Gjandia, Sumqayit
Bahrain: Alba
Brazil: Albras, Alumar, Aratu, Ouro Preto, Poços de Caldas, Sorocaba, Valesul
Cameroon: Alucam
Canada: Alma, Alouette, Arvida, Baie Comeau, Beauharnois, Bécancour, Deschambault, Grande Baie, Isle Maligne, Kitimat, Laterrière, Shawinigan Falls
China: Baotou, Baotou East Hope, Chalco Guangxi (Pingguo), Chalco Guizhou, Chalco Qinghai, Chalco Shandong, Chalco Shanxi Project, Chalco Zhengzhou, Chiping Xinfa, Danjiang, Emeishan, Fushun, Guangxi Bose Yinhai, Guangyuan Qimingxing, Guizhou Zunyi, Henan Huanghe Mianchi, Henan Jiaozuo Wanfang, Henan Longxiang, Henan Qinyang, Henan Shenhuo, Henan Xichuan, Henan Xin'an Wanji, Henan Xinwang, Henan Yulian Zhongfu, Henan Zhongmai Yong'an, Honglu, Hubei Huasheng, Hubei Yangxin Hongjun, Hunan Chuangyuan, Jilin, Lanzhou, Lanzhou Liancheng, Nanshan, Nantun, Qinghai Baihe, Qinghai Qiaotou, Qingtongxia, Sanmenxia Tianyuan, Shandong Weiqiao, Shandong Zouping, Shangqui Shangdian, Shanxi Guanlu, Shanxi Yangquan, Shanxi Zhaofeng, Shanxi Zhenxing, Sichuan Meishan Qimingxing, Tongchuan Xinguang, Tongliao, Yichang, Yichuan, Yunnan, Zhejiang Huadong, Zhengzhou Longxiang
Egypt: Egyptalum
France: Auzat, Dunkirk, Lannemezan, St. Jean de Maurienne
Germany: Elbewerke, Essen, Hamburg, Rheinwerk, Voerde
Ghana: Valco
Greece: St. Nicolas
Hungary: Inota
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Indonesia: Asahan
Italy: Fusina, Porto Vesme
Malaysia: Bintulu, Masco
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Netherlands: Delfzijl, Vlissingen
New Zealand: Tiwai Point
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Slovak Republic: Slovalco
Slovenia: Talum
South Africa: Bayside, Coega, Hillside
Spain: Aviles, La Coruña, San Ciprian
Suriname: Suralco
Sweden: Sundsvall
Switzerland: Steg
Tajikistan: TadAZ
Turkey: Seydisehir
U.A.E.: Dubal
U.K.: Anglesey, Lochaber, Lynemouth
Ukraine: ZALK
USA: Badin, Columbia Falls, Eastalco, Evergreen, Goldendale, Hannibal, Hawesville, Intalco, Longview, Massena, Mead, Mount Holly, New Madrid, Ravenswood, Rockdale, Sebree, St. Lawrence, Tacoma, Tennessee, The Dalles, Troutdale, Warrick, Wenatchee
Venezuela: Alcasa, Venalum

Financial Times (London, England)

July 10, 2007 Tuesday
London Edition 1

SECTION: LEX COLUMN; Pg. 18

LENGTH: 345 words

HEADLINE: **Mirror, mirror** on the wall THE LEX COLUMN:

BODY:

Most mirrors are glass, sprayed with a coating of aluminium - a fitting reminder to investors contemplating the London listing of Rusal, pencilled in for November, to take a good long look at themselves first. The Russian company is the world's biggest producer of aluminium, with an estimated equity value of Dollars 30bn. Even offering just 25 per cent of the company would make it one of the largest IPOs of the year.

It is commendable that Rusal is gunning for a full listing on the London Stock Exchange - Russian companies often prefer issuing global depositary receipts, which require them to jump through fewer hoops. But shareholder comfort on corporate governance must be matched by confidence that prices for aluminium will stay strong. The price has doubled since 2003, but an inability to break through Dollars 3,000 a tonne this year reflects concerns that conditions may be deteriorating.

High prices have meant that inefficient producers are keeping their smelters running, particularly in China, which now represents about 40 per cent of global production. Neither rising input costs nor export taxes have prevented China's rampant production from overflowing abroad. Only a domestic slowdown, it seems, might moderate production. But signs that the "China story" was softening would hit all commodity prices hard.

Bulls, however, reckon demand for aluminium will swamp short-term worries over supply. Consumption is accelerating in developing economies due to the strong correlation between a country's wealth and its use of aluminium. China and India, which combined are expected to account for about 30 per cent of consumption by 2010, have output per capita less than a sixth that of developed countries. In addition, prices of substitute metals such as copper and zinc have risen faster than aluminium over the past five years. That also spurs demand, although the situation could quickly reverse.

All well and good, but Rusal's challenge will be to persuade investors that even the most optimistic outlook is not already discounted in the aluminium price.

LOAD-DATE: July 9, 2007

Financial Times (London, England)

March 5, 2007 Monday
London Edition 1

SECTION: LEX COLUMN; Pg. 20

LENGTH: 305 words

HEADLINE: **Helter smelter** THE LEX COLUMN:

BODY:

China giveth and China taketh away. That certainly resonates with those taking a punt on aluminium. The metals market is focused on one huge long position built up recently. It is thought to be equivalent to between 50 and 80 per cent of all the aluminium sitting in London Metal Exchange's warehouses, just over 800,000 tonnes. There is also an unusually large number of March 2007 aluminium calls at strike prices of Dollars 3,000 a tonne or more outstanding.

Yet in spite of several runs up towards Dollars 3,000, spot aluminium has not breached that level and now sits at less than Dollars 2,800. The squeeze means even high-cost producers can keep their smelters running, and metal has been flooding into LME warehouses, with inventories rising by almost 70,000 tonnes in the past month alone. Producer stocks, held outside the LME, have also seen a big increase across the world.

The hopes and fears of aluminium traders largely rest on China. The view that tight supplies of raw materials and high energy prices would crimp Chinese production has proved unfounded. China continues to export aluminium. In January, the country imported more than 1.6m tonnes of critical raw materialbauxite - more than five times the amount landed in January 2006. Beijing's efforts to curb rampant production offer little comfort. Export taxes have so far proved ineffective. China now accounts for more than 40 per cent of global aluminium production. If taxes did lead to lower output, world prices would rise, incentivising Chinese producers to export regardless. Yet if the authorities did manage to slow the economy's expansion, that would hit all manner of risky asset classes, with commodities in the front line.

Commodities bulls have long trumpeted the fact that China is simply too big to ignore, but its impact is not a one-way street.

LOAD-DATE: March 4, 2007

Financial Times (London, England)

May 8, 2007 Tuesday
London Edition 1

SECTION: COMPANIES INTERNATIONAL; Pg. 25

LENGTH: 582 words

HEADLINE: Aluminium war becomes intense

BYLINE: By REBECCA BREAM and BERNARD SIMON

BODY:

Alcoa's hostile Dollars 33bn bid for Alcan is the latest step in the rapid consolidation of the aluminium sector.

If the audacious bid is successful, it will form a company almost twice as big as its nearest rival and the aluminium industry's equivalent of steel giant Arcelor Mittal.

But it is by no means a done deal. In spite of talking to Alcoa intermittently for two years about a possible tie-up, Alcan has resisted a deal and Alcoa has been forced to go hostile.

Alain Belda, Alcoa's chairman and chief executive, said yesterday the talks got as far as discussing the name of the new company and its management structure, but then broke down. Alcan said yesterday it would consider Alcoa's offer but shareholders should "defer making any decision".

The hostile nature of the bid raises the possibility that another metals group, such as BHP Billiton or Rio Tinto, could step in as a white knight.

There are also antitrust issues. The aluminium industry is already very concentrated, and a combination of Alcoa and Alcan would have a stranglehold on certain markets, such as supply of specialised aluminium to the aerospace sector.

Analysts yesterday interpreted Alcoa's bid as defensive and said the group was a candidate for a takeover.

Alcoa's stock has underperformed peers for some time. There has been intense speculation that BHP, Rio Tinto, or even private equity buyers intended to launcha bid.

Last month, Alcoa put its packaging and consumer divisions up for sale and said it would refocus on its core metals operations in an attempt to boost its share price.

The deal also reflects increasing competition from Russia. Last year, Rusal, the privately owned Russian aluminium group controlled by Oleg Deripaska, declared a takeover of smaller Russian aluminium producer Sual and the aluminium assets of Glencore, Swiss commodities trader.

Rusal has now overtaken Alcoa as the world's largest producer of aluminium. It is not surprising Alcoa would consider ways to recover its crown.

Alcoa said yesterday the deal would give annual **cost** savings of about Dollars 1bn. The enlarged Alcoa would have 188,000 employees; annual revenues of Dollars 54bn; and capacity to produce 7.8m tonnes of aluminium and 21.5m metric tons of alumina, the raw material for aluminium, each year.

Alex Gorbansky, managing director at Frontier Strategy Group, said the combination of Alcoa and Alcan would give the group more negotiating power when talking to governments about new **smelter** projects, especially the Middle East - a fast-growing hub of the **aluminium** industry thanks to its cheap energy supplies.

Aluminium smelters are multi-billion dollar investments and their future profitability depends on securing long-term, low-**cost** supplies of electricity, as the production process requires great energy.

That means size is important in the industry. The last decade has seen many smaller players snapped up by the largest companies, for example Alcan's 2003 takeover of Pechiney of France.

Mr Gorbansky added that the deal reflects optimism on the part of Alcoa about the outlook for aluminium prices, which have risen sharply on strong demand from China and India.

Excitement about Alcoa's bid prompted traders to ask which aluminium companies might be caught up in further consolidation. Shares in Norsk Hydro, Norwegian aluminium group, reached an historic high yesterday. Analysts pointed out, however, that the Norwegian government's 44 per cent stake in the companymight make it difficult to take over.

LOAD-DATE: May 7, 2007

Financial Times (London, England)

November 8, 2006 Wednesday

SECTION: FT REPORT - ALUMINIUM; Pg. 1

LENGTH: 1250 words

HEADLINE: Looking east as worldwide demand soars The surge in Chinese output and a big Russian merger show how the sector's geography is shifting, says Rebecca Bream

BYLINE: By REBECCA BREAM

BODY:

The geography of the aluminium industry is shifting. For decades companies in western Europe and North America have been at the forefront of the sector, accounting for most of production and doing most of the deals.

Alcoa of the US and Alcan of Canada have been dominant in the industry for years, and this was reinforced by Alcan's takeover of Pechiney of France in 2003, which gave it a leading position in smelter technology.

But the aluminium industry is increasingly looking east.

China has risen to be the largest aluminium producer in the world, as it has done in steel, from being the fourth-largest producer 10 years ago. This rise has taken place against a backdrop of rapid expansion in the global aluminium industry, making China's growth even more impressive.

According to CRU Analysis, the metals consultancy, China produced 1.5m tonnes of aluminium in 1996, compared to 3.6m tonnes for the US - then world number one. For this year, China is expected to produce 9.3m tonnes of aluminium, while the US, which has slipped to fourth place, will produce only 2.3m tonnes.

US companies are still important, but they are rapidly closing down their US smelters in favour of international expansion. While Alcoa produced 3.7m tonnes of metal last year, more than 1m tonnes came from its smelters outside the US, in countries including Canada, Brazil and Australia.

In corporate terms, the focus of the aluminium market is also shifting eastwards.

Rusal and Sual of Russia had been making noises about their global ambitions and pipelines of expansion projects for a couple of years, but last month the companies made their most decisive move yet. Sual agreed to be taken over by Rusal, its larger rival, to form United Company Rusal, the world's largest aluminium producer.

The negotiations for the deal between Russian oligarchs Oleg Deripaska, who owns Rusal, and Viktor Vekselberg, who owns Sual, were long-winded and opaque. The two sides had talked before, and had failed to agree.

But the industrial logic for Russian aluminium consolidation was strong, and the fact that Vladimir Putin, Russia's president, had blessed the combination meant that this time the two businessmen came to an agreement.

Rusal and Sual together produced 3.8m tonnes of aluminium in 2005, putting them only slightly ahead of Alcoa. The Russian companies have an impressive pipeline of new smelter projects, however, which could put more space between them and their competitors in the future.

Rusal is soon to open its new Khakassia smelter in southern Siberia, the first smelter to be opened in Russia since the fall of the Soviet Union. It is working on plans for a new smelter at Boguchansk, near Krasnoyarsk in Siberia, which could have a capacity of up to 600,000 tonnes per year.

Rusal has also talked about teaming up with Rosatom, Russia's nuclear power organisation, to help build a new nuclear plant in the far east of Russia. The company would build an aluminium smelter nearby, and then export the metal from one of Russia's eastern ports to customers in Asia.

One concern that aluminium producers have outside Russia about the Rusal takeover of Sual is that the creation of such a dominant national champion will make it harder for foreign groups to break into the Russian market. "You could envisage that other players will not have access to any Russian projects," says Torstein Dale SjÃ[#x192]Â,tveit, vice-president of aluminium metal at Hydro Aluminium of Norway.

Whether there is a future for aluminium production in the western world is a question that many in the industry are currently asking. Smelting aluminium is very energy-intensive and higher energy costs have been one the main factors driving aluminium prices up over the last few years. If producers cannot negotiate low-cost electricity supply contracts at home, they will move production to a region of the world blessed with abundant energy resources.

The decline of the US as an aluminium-producing nation, along with many in western Europe, reflects the fact that new capacity is being built in regions with lower energy costs, such as the Middle East and Russia.

Hydro has closed down two of its Norwegian smelters over the last 12 months, as they were not competitive, while Alcan has closed a Swiss smelter and plans to close a French plant next year.

Alcan said in recent weeks that it was reviewing the future of its 200,000 tonne-a-year Vlissingen plant in the Netherlands after two years of

talks with the energy supplier over a new supply contract failed to yield the desired result. Vlissingen's current energy contract ends next year.

Mr SjÃ[#x192]Â,tveit at Hydro says high metals prices, plus a drop in the price of alumina, a raw material for aluminium, "is keeping some smelters going for longer than expected". But he thinks that the shift away from North America and Western Europe is irreversible.

"In the future you will not find big smelters in highly populated places with high energy prices," he says. "The location of smelters will move further away from the consumer." This has implications for the transportation of aluminium, adds Mr SjÃ[#x192]Â,tveit, and may mean more smelters are built close to ports, to ease import of raw materials and the export of finished metal.

Canada is one western country that seems to have a healthy aluminium industry, thanks to its hydroelectric power supplies. In 1996 it produced 2.3m tonnes of aluminium, and this year its output is predicted to be 3m tonnes.

Alcan plans to spend USDollars 1.8bn on expanding its Kitimat smelter in British Columbia by 63 per cent to produce 400,000 tonnes a year. The group says that, after the expansion, Kitimat will be one of the world's lowest cost smelters.

Wherever the metal will be produced, it is clear that there will be more of it around. "Growth in global aluminium production is set to hit a record 2.7m tonnes next year as new capacity comes on stream in Russia, China and Iceland, while (smelter) restarts take effect in Germany, the US and China," says Ross Strachan, a consultant from CRU Analysis.

Demand for aluminium is also forecast to remain robust, which should support a high metal price. Aluminium currently costs just under Dollars 2,800 a tonne, compared to Dollars 2,000 a tonne 12 months ago, and analysts have predicted that this will fall only slightly in 2007.

The key areas of demand for aluminium are from the aerospace, automotive, construction and packaging industries.

Alcan says that demand overall is likely to slow in North America, but is still "quite strong". Europe has demonstrated surprisingly strong demand, but Alcan has found this mainly coming from eastern Europe, where the construction and consumer goods industries are booming.

There has has been a shortage of around 300,000 tonnes of aluminium in the global market this year, one of the reasons that the price has risen so much, touching a peak of Dollars 3,300 a tonne in May.

Dick Evans, chief executive of Alcan, says: "Supply and demand will be approximately in balance in 2007." He says the fall in alumina prices and the growth in metal supply will depress prices slightly, but the market will be less cyclical than it has been in the past. "Our mid-term outlook is that we don't see a bust," he says.

Mr Evans adds that, if the aluminium price did fall significantly, China's leading position in metal production could be threatened. "If prices were to fall to Dollars 2000 a tonne, we think quite a lot of capacity in China and Western Europe would come off line."

LOAD-DATE: November 7, 2006

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Financial Times (London, England)

November 8, 2006 Wednesday

SECTION: FT REPORT - ALUMINIUM; Pg. 3

LENGTH: 1105 words

HEADLINE: Control of energy is key to success INTERVIEW DICK EVANS OF ALCAN: It is one of the main ways to be competitive in smelting, the Canadian company's chief tells Rebecca Bream in a wide-ranging review of prospects

BYLINE: By REBECCA BREAM

BODY:

Dick Evans, chief executive and president of Alcan, the Canadian aluminium company, is sanguine about the changes taking place in the global aluminium industry.

The business has always been dynamic, he says, and the shift in production of primary metal away from North America and western Europe is nothing new. "The location of aluminium production has been shifting for the past 30 or 40 years, there has been a dramatic decline (in North America and western Europe). The increase in production has come mainly from China and the Middle East."

Russian aluminium production is set to expand rapidly in the coming years, but as yet China's position as the number one producer in the world is unchallenged, he says. "I don't see that changing in the medium term. They are still building capacity."

Mr Evans, who was promoted to the top job at Alcan in March following the departure of previous chief executive Travis Engen, thinks there is a future for some aluminium production in North America and Western Europe, however. "There are pockets of production that have actually grown considerably, such as Iceland."

The key is energy supply. Iceland has access to both geothermal energy, using heat from the earth's core, and hydro-electric energy. Canada is also well-endowed with hydro-electric generating capacity, and the two countries account for more than half of Alcan's metal production. The group is currently considering building a second smelter in Iceland, says Mr Evans.

One of the main ways to be competitive in aluminium smelting is to control your energy supplies, he says. "In Canada, we own 100 per cent of our energy in British Columbia and 80 per cent in Quebec.

"Worldwide, we are between 50 and 60 per cent covered in our energy needs, and we have long-term contracts on another 35 per cent. Less than 10 per cent of our energy is supplied on short-term contracts." This has led to a significant drop in Alcan's production costs over the last two years.

In August Alcan announced it was to invest USDollars 1.8bn in expanding and modernising its Kitimat smelter in British Columbia, which runs on hydro-electric power. When the work is finished in 2011, production will rise from 245,000 tonnes to 400,000 tonnes a year, and Kitimat will be one of the three lowest cost smelters in the world, says Mr Evans. It will also be one of the three largest smelters in North America.

Alcan has always tried to own its own energy resources, and this is now the deciding factor in the location of the company's new smelter projects. "When you build a smelter you need to secure energy supplies for at least 20 years. But this is very difficult to do now, energy assets are expensive," says Mr Evans.

An example of this has been the wrangling over the Coega smelter project in South Africa, which Alcan inherited from Pechiney when it took over the French company in 2003. A decision on whether to build the smelter has been delayed for several years while Alcan and Eskom, the South African power supplier, have negotiated terms of an energy contract.

Mr Evans is optimistic that these talks will be concluded "soon", and that the Coega project will finally get started. "Once we get the power contract secured, we will start an increased emphasis on the design of the facility, and on partners."

Alcan does not need to bring in a partner, he says, but the group is considering selling a stake of 30 per cent to another aluminium producer. "All the major players have said they would be interested," says Mr Evans. "It will be an attractive project."

Smelter technology-watchers will be disappointed to hear that the Coega project is unlikely to include Alcan's cutting edge AP50 equipment, as Pechiney had originally intended. AP50 is regarded by many in the industry as the most advanced smelting technology around; its bigger pots mean it is more efficient in terms of capital and labour.

The plan is for Coega to use AP35 technology, says Mr Evans, as AP50 is not ready for commercial application yet. The group plans to build half a AP50 pot-line near an existing smelter as a trial "in the next few years".

Alcan has not neglected the AP50 technology since it bought Pechiney, says Mr Evans. "We have continued to develop it, the technology has improved since we acquired it. As other (companies) catch up we are pushing the technology further ahead, and making further strides in energy efficiency."

One feature of the current market that does bother the usually unflappable Mr Evans is the underperformance of aluminium company shares. Alcan and Alcoa stock have not risen as fast as the price of aluminium on the metals exchanges. "It is the biggest gap I have seen in 37 years in the industry between what the commodities market is telling me, which is bullish, and what the equity market is telling me, which is bearish."

Mr Evans says the lacklustre trading of aluminium stocks has been caused partly by speculators and hedge funds shifting their money out of the sector, and partly by investor concern about the affect a US recession or a Chinese crash. But this is "an overreaction" he says. "What is being missed by the equity markets is that demand for aluminium in China continues to grow by 20 per cent per year, and we see no slowing in this, while growth in production capacity is declining."

Mr Evans says his group hoped to stimulate Alcan's share price by buying buying back shares. Alcan said last month that it would buy up to USDollars 750m worth of its own stock over the next three to six months. "It is a sign that we think our shares are considerably undervalued."

On the subject of mergers and acquisitions, Mr Evans says Alcan is not looking for a huge, company-transforming deal. Although the group is looking for acquisitions in the downstream market, such as packaging, Alcan intends to grow organically upstream by building its own smelters rather than buying them.

"China is a possibility for further acquisitions," says Mr Evans. Alcan has owned a 50 per cent stake in the Qingtongxia smelter in the Ningxia region of central China since 2002. The 130,000 tonne-a-year smelter was built in 1999 and uses modern prebake technology.

Alcan has also moved into Russia in recent years, buying rolling mills from Rusal. Mr Evans says he views the takeover of Sual of Russia by larger compatriot Rusal as positive for the aluminium market, as there will be no short-term impact on the amount of metal being produced, but it should lead to better corporate governance and environmental standards in the Russian industry.

"Ultimately they want to go public, so they will want to meet western standards," he says.

LOAD-DATE: November 7, 2006

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Financial Times (London, England)

November 8, 2006 Wednesday

SECTION: FT REPORT - ALUMINIUM; Pg. 5

LENGTH: 802 words

HEADLINE: Long-term issues to resolve NORTH AMERICA: Alcoa and Alcan are shrugging off the threat from Russia, says Daina Lawrence

BODY:

North America's two biggest aluminium companies are shrugging off a mounting threat from their fast-growing and low-cost Russian rivals.

"They are confined to Russia so far," says Michel Jacques, head of Alcan's primary metal group. "And I think we have excellent costs."

But this was not the case five years ago. With the cost of operations, particularly power costs in the north-western US, on the rise in the last few years, there have been gradual closures of smelters all over North America.

In 2001, Alcoa was forced to cut its smelter production by 150,000 tonnes a year in the American Northwest due to these rising energy costs. In 2005, the company announced it would close its Frederick, Maryland smelter and it remains idle today.

The past few years have been shaky for Alcan's North American smelters as well. The company also announced several smelter closures, including its Jonquiere Soderberg smelter in Arvida, Quebec in 2004.

Rusal, soon to merge with smaller rival Sual, has several smelters located in Siberia with access to cheaper power and operating costs. This may give the Russian group a clear advantage, but both Alcan and Alcoa say they are not looking at this as a major threat.

Analysts agree that the Russian aluminium sector may not represent an immediate threat to North American producers. But Carlos De Alba and Mark Liinamaa from Morgan Stanley warn that thinking too short-term may be a dangerous option.

According to Mr Liinamaa, Russia may not be a powerhouse just yet, but there is still time to improve. "They have old technology and maybe not the most efficient (production)," he says. "But once they gain access to financial markets and raise capital then they'll become a much more important threat."

These analysts say Alcan's location in Canada may work to its advantage in the future. Alcan operates the majority of its smelters in Canada, and Quebec in particular. Producing its own power in its plants and accessing hydro electricity at cheaper rates, has kept the company's costs down.

"Longer term, Russia is a more important threat to at least the US smelters, Canada has cheaper power and Alcan has access to it," says Mr De Alba. "So they are better prepared to deal with this new threat."

Closing older smelters in favour of investing in places with cheaper power, such as Iceland and parts of Europe, may give the impression that business is not looking good for North America. But some of the closures and reductions have not been permanent.

Just this past summer, Alcoa announced that plants in Wenatchee, Montana and Ferndale, Washington would resume production. Alcan and Alcoa, despite having to close smelters in the past, say they are both willing to invest in North America and are already planning new smelter projects there.

Alcan recently reported it plans to spend USDollars 1.8bn on expanding its Kitimat smelter in British Columbia by 63 per cent to 400,000 tonnes. Construction is expected to start in the second quarter of next year.

Alcoa has also been investing in its North American smelters for the past few years to help the company stay on top of the global market. Throughout 2006, work continued on environmental upgrades at the company's Warrick, Indiana smelter which will help secure its power generation self-sufficiency. At the Intalco smelter in Ferndale, Washington - a smelter once hit by reductions - the company will be starting up a second potline which will produce an additional 7,500 tonnes per month beginning in the first half of 2007.

In May 2005, the aluminium giant announced it would be investing Dollars 45m to buy equipment and the rights to mine coal for its aluminium smelter in Warrick, Indiana. The idea behind all this, explains Kevin Lowery, Alcoa's director of corporate communications, is that the company wants to invest in its smelters at home, make them more self-sufficient and work at ways to reduce logistical costs.

Rusal, currently third in the world in aluminium production, has also been investing funds into its Russian operations in an attempt to boost its aluminium output.

But Alcoa is taking a similar approach to Alcan, and saying it cannot concern itself with the activity in Russia at this time. For now the two companies plan to concentrate on securing a long-term, competitively priced, energy source to help reduce their power costs.

At present, Alcan and Alcoa may be more stable than a few years ago, in terms of energy costs. They have invested in building the capabilities for self-sufficient power or are securing contracts with power suppliers, but this may not last forever, says Mr De Alba at Morgan Stanley.

"They could be relatively safe for the next few years. However when those contracts come to an end and they have to renegotiate, that's when we will see this become an issue," he says.

LOAD-DATE: November 7, 2006

Goldman Sachs

Americas: Metals & Mining

We see above consensus metal prices on improving fundamentals

We are making changes to our metals & mining primary coverage

Oscar Cabrera is assuming coverage of Alcoa, Alcan, Century Aluminum, Freeport McMoran, Antofagasta, Southern Copper and Grupo Mexico from Hongyu Cai. We now retain a single Base Metal coverage group.

Copper best positioned in our upgrade to base metals sector

We are upgrading our coverage view for the base metal sector from Neutral to Attractive. Freeport McMoran (FCX) is our top pick in our base metal coverage universe. We re-iterate our Buy rating on FCX and see a 30% upside to our new 12-month target price of $95 per share (raised from $79), which is based on NAV, EBITDA and P/E-based valuation analysis. The key risk is lower copper prices. However, we see improving copper fundamentals, supported by re-stocking in China, an improving 2008 global economic outlook and continuing supply disruptions. Thus, we project above-consensus 2007-09 copper prices at $3.20, $3.40 and $3.00 per lb, respectively. We also remain bullish on gold and re-iterate our CL-Buy rating on Barrick. We believe a super-spike "phase -2" in crude oil and gasoline provide upside potential to our estimates (see our May 6 note).

Sustainabilty is the source of the opportunity

Our upgrade is premised on sustainable above-consensus metal prices for 2008-09, not on a short term spikes following increased metal demand in 1Q07. We favor copper fundamentals over nickel, zinc and aluminum. Our 2008E EPS estimates for copper equities are 30% above consensus (with Freeport at 45% above); we see improving balance sheets and greater potential for increased cash returned to shareholders. Base metal companies trade at a 2008E P/E of 9.1x and EV/EBITDA of 5.4x, compared to historic forward P/E ranges of 8-17x and 3.5-8.0x EV/EBITDA. Target prices for our base metals universe reflect an average 2008E 9.6x P/E and 5.7x EV/EBITDA, compared to copper equities 9.1x P/E and 4.4x EV/EBITDA.

Catalyst

The key catalyst for the sector, specifically copper levered equities, is the significant positive EPS revisions we expect to consensus 2007E and 2008E

Risks

The key risk to our bullish view would be an unexpected sharp macroeconomic slowdown, leading to lower base metal prices.

Metal Price Forecasts				
		2006	2007E	2008E
Aluminum	US$/lb	1.17	1.20	1.10
Copper	US$/lb	3.05	3.28	3.40
Nickel	US$/lb	10.96	17.15	13.65
Zinc	US$/lb	1.48	1.58	1.40
Gold	US$/oz	605	669	734
Silver	US$/oz	11.59	13.07	11.50
Month-on-month performance				
Commodities		5/13/2007	4/12/2007	%ch
Aluminum		1.29	1.27	1.7%
Copper		3.61	3.51	2.9%
Nickel		24.24	22.02	10.1%
Zinc		1.85	1.59	16.4%
Gold		671	676	-0.8%
Silver		13.23	13.90	-4.8%
Platinum		1,329	1,262	5.3%
Palladium		367	371	-1.1%
Crude Oil		62.37	63.85	-2.3%
Indices				
XAU index		137.03	137.78	-0.5%
GSCI		41.9	40.25	4.1%
S&P 500		130.5	131.5	-0.8%
Dow Jones		19.53	19.53	0.0%
Currencies				
EURO/US$		1.3329	1.3283	0.3%
AUD/US$		33.37	33.37	0.0%
US$/YEN		118.02	118.09	-0.1%
US$/CAD		1.1583	1.1605	-0.2%
US$/ZAR		7.273	7.196	1.1%
Equities				
Barrick	ABX	28.85	29.07	-0.8%
Newmont	NEM	42.49	43.54	-2.4%
Anglogold	AU	44.52	45.53	-2.2%
Gold Fields	GFI	18.24	18.17	0.4%
Buenaventura	BVN	29.66	29.95	-1.0%
Hochschild	GB;HOC	330	333	-0.9%
CVRD	RIO	37.02	36.98	0.1%
Teck Cominco	CA;TCK/B	81.2	80	1.5%
Penoles	MX; PEO	127.57	122.01	4.6%
Alcoa	AA	33.68	34.19	-1.5%
Alcan	AL	52.78	52.53	0.5%
Freeport	FCX	65.35	62.3	4.9%
Antofagasta	GB;ANTO	10.1	10.1	0.0%
Century Aluminum	CENX	46.39	46.45	-0.1%
Grupo Mexico	MX;GMEX	50.91	48.92	4.1%
Southern Copper	PCU	71.56	70.72	1.2%

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changes, as well as risks to these target prices can be seen in Exhibit 8. We remain Not Rated on Alcoa and Alcan. In addition we have lowered our target price for Industrias Peñoles to P110 per share from P120 as we adjusted our zinc price estimates.

Exhibit 8: Risks to our target price estimates
Most risks are metal price related

Macro-economic and other general steel sector risks

Macro risks that could impact all base metal companies include a significant economic slowdown in major metal consuming regions, particularly China, the US or EU. Over-production and excess exports out of China is a major risk for zinc and aluminum production. Any of these events could deteriorate the global supply/demand balance, pushing base metal prices down. Stronger local currencies at major commodity based economies (i.e. Canada, Brazil, Australia, Chile, Peru, Indonesia) vs the US dollar could also be a negative.

Target Price Methodology

Our 12-month target price for base metal companies (AA, AL, CENX, FCX, PCU, GMEX, PENOLES, ANTO, RIO, TCK) is based on P/E, EV/ EBITDA and Net Asset Value calculation. We utilize a 6% discount rate benchmark for mining operations in low sovereing risk countries (i.e. US and Canada). Our benchmark increases between 200 an 400 bps, based on sovereign risk and potential technical risk.

Company	Rating	Target Price	Old Target Price	Commentary on Risks
Alcan Inc.	NR			Not Rated
Alcoa	NR			Not Rated
Antofagasta	Neutral	597 p	559 p	Ongoing labor disruptions in Peruvian and Mexican operations. High payout ratio may limit asset development in a weaker copper price environment. Decline of copper and zinc prices driven by a Global economic slowdown.
Century Aluminum	Neutral	$55	$46	Increased electricity rates at Century's US based aluminum smelters or alumina spot prices (Century is net short over 50% its alumina requirements). Decline of aluminum prices due to a Global economic slowdown or China's net exports.
CVRD	Buy	$51	$49	Weakness in stainless steel markets (approximately 60% global consumption of nickel), Inco merger integration and a slowdown in iron ore demand due to a reduction in Chinese steel production or a Global economic slowdown.
Freeport McMoran	Buy	$95	$78	Increased financial leverage following the acquistion of Phelps Dodge, integration of PD assets, increased technical risk at Indonesian operations as Grasberg moves completely underground. Decline in copper prices due to a Global economic slowdown.
Grupo Mexico	Neutral	$66	$54	Pending environmental liabilities from Asarco LLC, increased diversification into other industries impacting holding company discount and decline in copper and zinc prices due to a Global economic slowdown.
Industrias Peñoles	Sell	P 110	P 120	On the upside, increased demand on silver derivative instruments that may lead to higher silver prices. On the downside, underperformance of mine operations that have led to costly third party concentrate purchases.
Southern Copper	Neutral	$91	$79	Ongoing labor disruptions in Peruvian and Mexican operations. High payout ratio may limit asset development in a weaker copper price environment. Decline of copper and zinc prices driven by a Global economic slowdown.
Teck Cominco	Buy	C$59	C$51	Capex overruns in the development of oil sands project. Weakness in met coal market due to Chinese coking coal oversupply. Decline of zinc prices driven by a Global economic slowdown or increased supply from Chinese mines (1/3 of world supply).

Source: Goldman Sachs Research estimates.

Adjusting our 2007-08 EPS estimates and introducing 2009 EPS estimates: We have adjusted our 2007-09 EPS estimates for CVRD in order to account for higher copper and aluminum prices, while Industrias Peñoles and Teck Cominco were positively impacted by changes in copper prices during the same period, offset by minor adjustments to our zinc prices in 2007-09. In addition we have adjusted our 2007-08 EPS and introduced 2009 EPS estimates for Alcoa, Alcan and Century Aluminum in order to account for said changes to aluminum prices. Similarly we have adjusted our 2007-08 EPS and introduced 2009 EPS estimates for Antofagasta, Southern Copper, Grupo Mexico. These companies estimates were positively impacted by our higher copper price estimates in 2007-09, offset by adjustment to our zinc price estimates.

July 31, 2007

COMMENT

Alcan Inc. (AL) $96.80

First-Take: Strong 2Q07 EPS, maintains positive aluminum outlook

News

Alcan reported 2Q2007 EPS of $1.64 (excluding $0.02 charge on derivatives), lower than our $1.69 estimate and consensus of $1.71. Business Group Profit (BGP) was 13% lower than our estimates as weaker results from the primary, engineering and packaging largely offset the strong results the alumina segment. Lower than expected operating results were partially mitigated by lower taxes and interest expenses. Alcan maintains its market balance forecast of a modest 200kt surplus, but remains positive on the outlook for aluminum.

Analysis

Alcan has demonstrated great execution and cost containment; however higher energy and raw materials prices, plus the strong appreciation of the CAD, EUR and AUD impacted our estimates. Alcan continues to benefit from strengthening aluminum prices, however cost pressures in the aluminum industry continue. In terms of aluminum prices, we believe the positive momentum could continue in the near term. However, we remain cautious longer term due to rapid alumina and aluminum supply additions. We maintain our Neutral rating on Alcan as we assign a high probability that Alcan shareholders will tender to Rio Tinto's (RTZ) $101/share offer. We believe Rio Tinto's offer is fully priced based in our aluminum price estimates as the bid places Alcan's 2008 EV/EBITDA at 9.1x EV/EBITDA compared to an mining and metals peer average of 5.8x. Alcan expects the transaction to close by 4Q2007.

Implications

Watch for: (1) Alcan conference call today at 10:00 am (EST). Dial in number: 877-421-3963. (2) Update on its project development pipeline, including the Gove alumina refinery expansion and its Kitimat modernization. (3) Update of energy and raw material costs pressure. (4) Details on Alcan's aluminum market outlook. (5) Updates on Rio Tinto offer. Our estimates and price target are under review.

INVESTMENT LIST MEMBERSHIP
Neutral

Coverage View: Attractive
Canada:
Metals & Mining

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July 24, 2007

COMPANY UPDATE

Century Aluminum Co. (CENX)

Neutral

Inline 2Q07 results driven by strong aluminum production

What's changed

Century Aluminum reported 2Q07 EPS of $1.69/share, in-line with our and consensus estimates, excluding after tax adjustments of $3.46/share (including a mark-to-market charge of $3.66, deferred taxes gains of $0.13, early extinguishment of debt charge of $0.06). Shipments, revenue and costs were mostly in line, with higher SG&A offset by lower interest expense. (Exhibit 1.) Further expansion of Grundartangi Iceland smelter to 260kt is proceeding well, with completion expected by 4Q07. CENX previously announced a major breakthrough in securing power supply, hat should support 250,000 tonnes of aluminum production. We are adjusting our 2007-09 estimates to factor lower interest expense, offset by spot alumina purchase, continued energy cost pressures and higher diluted shares outstanding.

Implications

We re-iterate our Neutral rating on Century Aluminum, however we have increased our 12-month target price to $65/share (from $53), factoring higher 2007-08 estimates and a multiple re-rating in our base metal coverage. We believe the latter is warranted given the sustainability of the current metal price cycle. Thus, we have increased our P/E and EV/EBITDA multiples used in our target price analysis.

Valuation

Our 12-month target price for CENX is based on an average of P/E, EV/EBITDA and Net Asset Value calculations. We maintain our Neutral rating, but believe speculation on industry consolidation, as well as short term strength in aluminum prices could support shares in the near term. CENX continues to trade at a discount to its aluminum peers at a P/E of 9.2x and EV/EBITDA of 5.3x, based on our 2007 estimates.

Key risks

On the upside, an extended period of high aluminum prices and on the downside delays in the ramp up of Grundartangi.

INVESTMENT LIST MEMBERSHIP

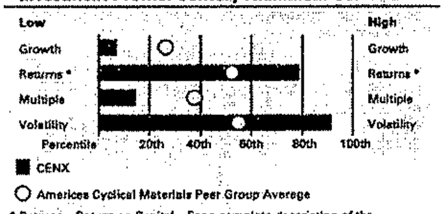
Neutral

Coverage View: Attractive

United States

Metals & Mining

Investment Profile: Century Aluminum Co.



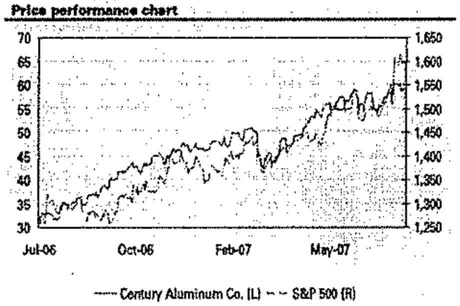
* Returns = Return on Capital. For a complete description of the investment profile measures please refer to the disclosure section of this document.

Key data	Current
Price ($)	61.59
12 month price target ($)	65.00
Market cap ($ mn)	2,109.1

	12/06	12/07E	12/08E	12/09E
Revenue ($ mn) New	1,558.6	1,796.6	1,746.2	1,727.0
Revenue ($ mn) Old	1,558.6	1,802.7	1,746.2	1,727.0
EPS ($) New	6.11	6.67	6.35	6.75
EPS ($) Old	6.11	6.47	6.05	6.41
P/E (X)	10.1	9.2	9.7	9.1
EV/EBITDA (X)	5.0	5.3	5.6	4.7
ROE (%)	111.4	57.5	29.8	24.2

	6/07	9/07E	12/07E	3/08E
EPS ($)	1.69	1.68	1.47	1.56

Price performance chart



Share price performance (%)	3 month	6 month	12 month
Absolute	25.9	42.6	89.7
Rel. to S&P 500	23.4	35.9	58.3

Source: Company data, Goldman Sachs Research estimates, FactSet. Price as of 7/24/2007 close.

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Solid 2Q07 results driven by high aluminum production

Overall, results were in-line with our expectations for Century Aluminum. Shipments, revenue and costs were mostly in line, with slightly higher SG&A offset by lower interest expense. The company provided further updates on development projects, stating that the Nordural brownfield expansion is on-track for completion at the end of the year and that its necessary power contracts for their Greenfield expansion in Iceland should provide supply for 250,000 tonnes of aluminum production.

Exhibit 1: CENX 2Q07 results summary
Inline results driven by strong aluminum production

	2Q07 GS Est	2Q07 Act	QoQ $ Diff.	QoQ % Diff.
Operating EPS - $/sh	$1.69	$1.69	($0.01)	0%
Direct Production (US)				
Realized price - $/lb	$1.20	$1.19	($0.01)	-1%
Shipments - mn lbs	291.9	292.1	0.2	0%
Revenues - mn $	$351	$348	($3)	-1%
Tolling Production (Iceland)				
Realized price - $/lb	$0.97	$0.95	($0.01)	-2%
Shipments - mn lbs	123.7	123.8	0.1	0%
Revenues - mn $	$119	$118	($2)	-1%
Income Statement (mn$)				
Revenues	$470	$464	($6)	-1%
COGS	$354	$356	$2	1%
Gross Profit	$117	$108	($8)	-8%
S.G.& A.	$12	$14	$2	17%
Operating Income	$105	$94	($11)	-11%
Net Interest Expense	($9)	($7)	$2	-21%
EBT	$96	$87	($9)	-11%

Source: Goldman Sachs Research estimates, Company reports

Increasing our 2007-09 estimates and target price

We are adjusting our 2007-09 estimates for Century Aluminum. Debt reduction resulted in lower interest expense, offset by continued cost pressures (i.e. electricity), assumed spot purchase of alumina due to aluminum production creep and an increased share count (40.9 million shares) following the completion of Century's secondary equity offering. Exhibit 2 provides a summary of these changes.

July 16, 2007

Goldman Sachs

Metals & Mining: Base Metals

High Yield

Credit Research

Aluminum: Demand and technicals trounce supply...for now

Aluminum prices ranged within a high, narrow band in 1H2007

Aluminum prices remained lofty during the first half of the year, averaging approximately $1.24 per pound in the first quarter and $1.27 through the second quarter. While we had not previously forecast quarterly aluminum prices for 2007 (our full-year aluminum price forecast was $1.04), we had expected prices to trend down from their 4Q2007 average of $1.23. This was clearly not the case. Also interesting was the relative *lack* of volatility in aluminum prices versus other base metal prices in 1H2007: Aluminum fluctuated within a ~$0.05/lb band; meanwhile, copper went from $2.64/lb to $3.70/lb and then back to $3.30/lb, nickel soared from just over $15/lb to $23/lb by the end of May, and zinc fluctuated between $1.50 and $1.90/lb.

Why the solid, yet uneventful performance? We see two reasons: (1) Strong demand – this was the same reason why prices were higher than we had expected during 2H06; and (2) technical factors related to trading within the base metals complex.

We continue to expect supply to overwhelm technical factors

We probably sound like a broken record with this argument – and an incorrect broken record at that. However, while demand has surpassed our expectations for the last few quarters, we cannot help but feel uneasy about the significant amount of aluminum supply set to enter the market this year and next year. While we do not expect aluminum prices to decline much below $0.90/lb, as that is around where the marginal cost of higher-cost production is, we continue to expect prices to decline as notable supply overwhelms strong demand.

Downstream volumes in the US are floundering, but we see value in Indalex and Aleris

Data from the US market have not been uplifting, with the likes of Indalex and Aleris forecasting weak US volumes through the remainder of 2007 owing to the housing and transportation sectors. Even so, we calculate that these companies should have the liquidity to weather this year. With the recent widening in credit spreads, we think their bonds continue to offer value for high yield investors. We believe Indalex's bonds offer an attractive yield for secured debt; as for Aleris, we think weakness in the markets has unduly pressured its senior subordinated notes wider despite solid cash flows and the recently-announced Wabash Alloys acquisition (which we view as a credit positive).

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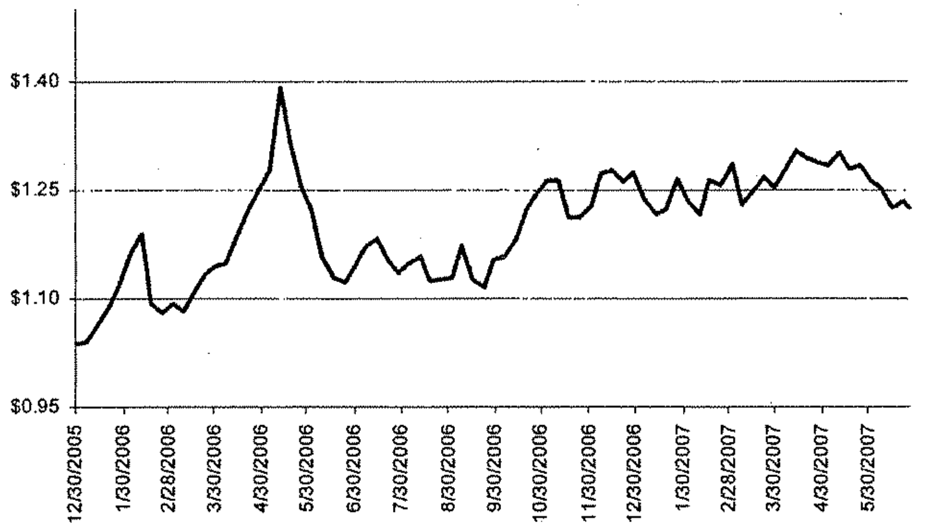
Exhibit 6: Aluminum prices have remained lofty
(cents. lbs)



Source: AMM.

As far as fundamentals in the market are concerned, we think aluminum prices were held higher by demand that was far stronger than our forecast – supply certainly did not do much to help the picture.

Supply has not aided the price story, as it continues to increase rapidly

Global aluminum production was up 11.6% year over year during 1Q2007, according to the CRU. We want to point out two outstanding supply trends.

First, supply in the US has been increasing this year, as high aluminum prices have encouraged companies to re-start older, higher-cost capacity. Ormet and Alcoa have both re-started smelters this year, and we expect these and others to push US production up by 4% to just over 5.5 million tonnes in 2007.

Second, and certainly of no surprise, China has substantially increased its production. Chinese production in the first quarter was up approximately 39% year over year, and we expect it to be up 30% for the full year 2007.

Century Aluminum Company

Ratings: B1/BB-
Outlooks: Stable/Stable
GS Rating: In-Line

Century Aluminum Company benchmark securities

TKR	GS Rating	Size (MM)	Coupon (%)	Priority	Maturity	Agency Ratings	Next Call Price	Next Call Date	Bid Price	YTW (%)	STW (bp)
CENX	IL	$250	7.50	Sr Nts	15-Aug-14	B1/BB-	103.750	15-Aug-09	100.250	7.430	242

Operations progressing solidly, CENX is one of the smaller primary aluminum players left

Century Aluminum should benefit from the fact that LME prices remained high and stable through the first half of 2007. The company's new smelter in Iceland has ramped up to full capacity, and we expect the second quarter to have been another strong one operationally.

More important for bondholders, Century raised approximately $416 million during the second quarter by selling equity. The company expects to use these proceeds to repay debt and to help finance construction of its second major Iceland smelter near Helguvik. We think attention to leverage is positive for the credit.

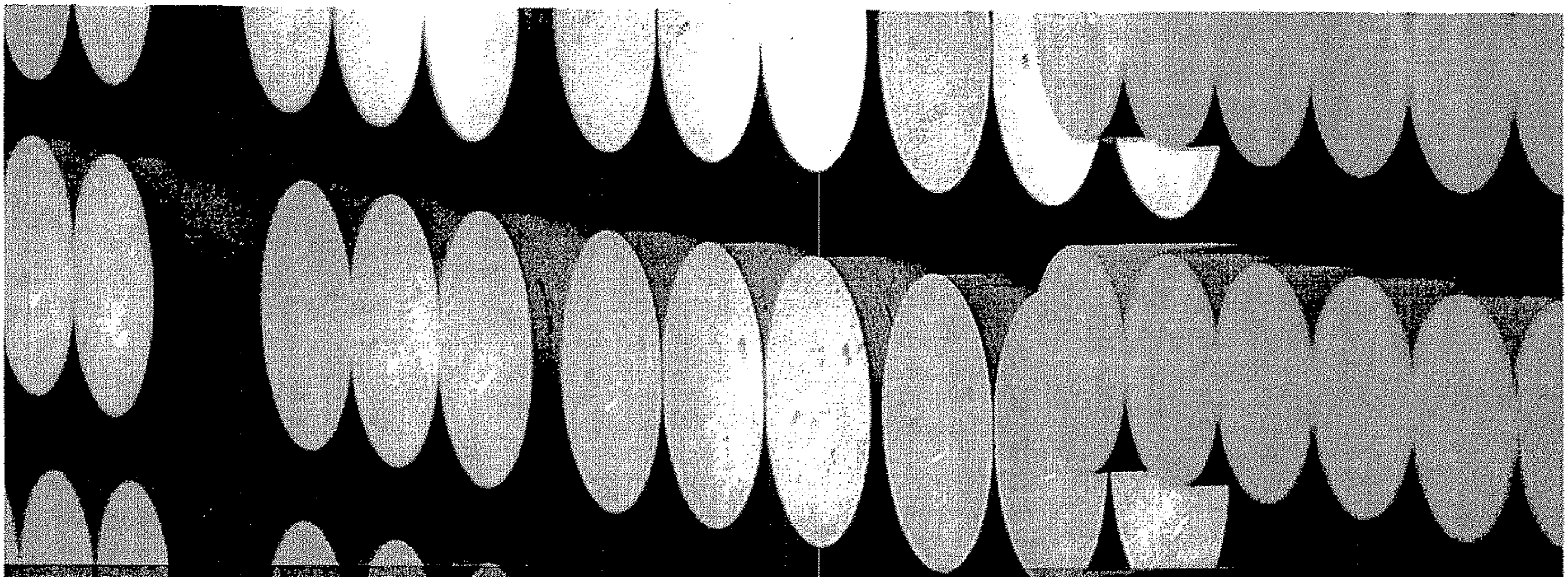
Finally, we want to point out that consolidation is proceeding at a rapid clip in the aluminum industry. Century remains one of the only smaller public producers left with access to raw materials (its 50% interest in both a bauxite mine in Jamaica and an alumina refinery in Louisiana), low-cost assets (the Iceland smelter), and several expansion projects in the works (primarily the Helguvik smelter, but also several memoranda of understanding for new projects in places like Africa and China). Granted, Century's US smelters are relatively high-cost on a global scale, and much of the production from its Iceland smelter is already contracted under tolling arrangements. Nevertheless, we expect consolidation to be a topic of conversation on the company's conference call.

We continue to rate Century's bonds In-Line as they trade at tight levels. But we think operations here are strong and we applaud the company's use of equity as currency to help keep leverage down while financing growth. We expect positive sentiment surrounding industry consolidation to help keep a cushion under the trading level of the bonds, despite our bearish outlook for primary aluminum prices.

A viable society. A need. An idea. 36,000 professionals. Energy. Cooperation. Aluminium. Determination. Pushing boundaries. Respect. Nature. Courage. 100 years. Thinking ahead.

Supply and demand for aluminium 2005 - 2015

Arvid Moss
Head of Metal Products, Aluminium



Supply and demand for aluminium 2005 - 2015

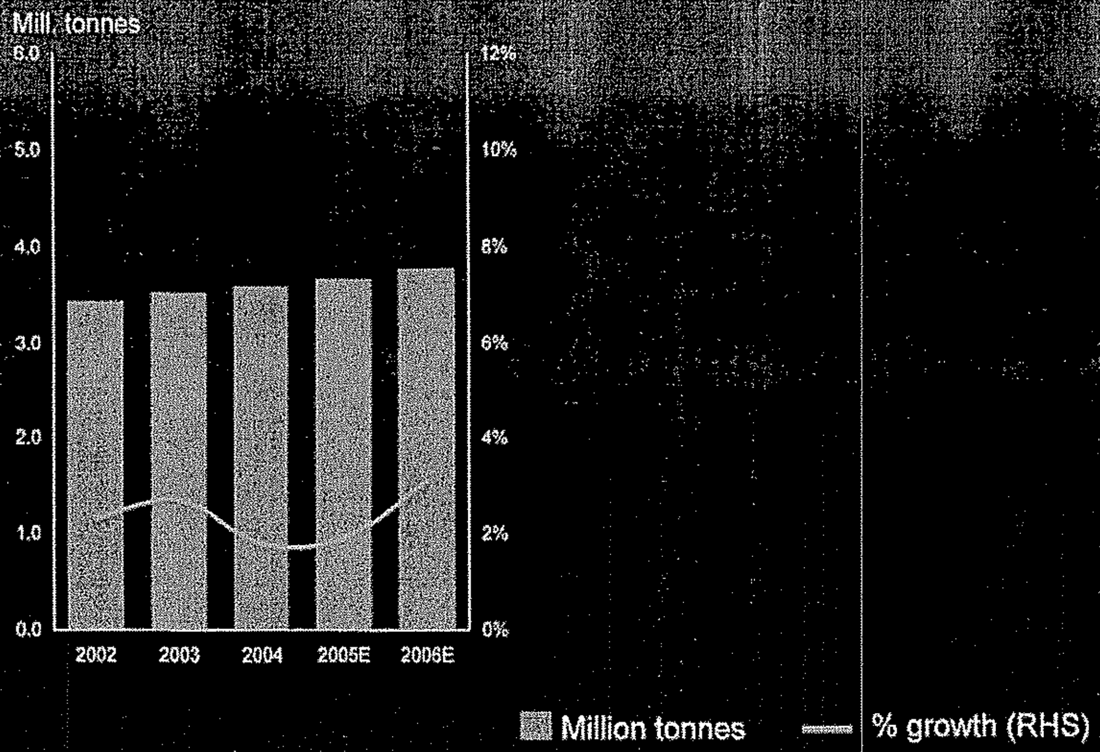
- Downstream consumption 2002 – 2006
- Primary market balance 2005 – 2006
- Long-term outlook

HYDRO

Rolled Products consumption

Moderate growth rates in Europe

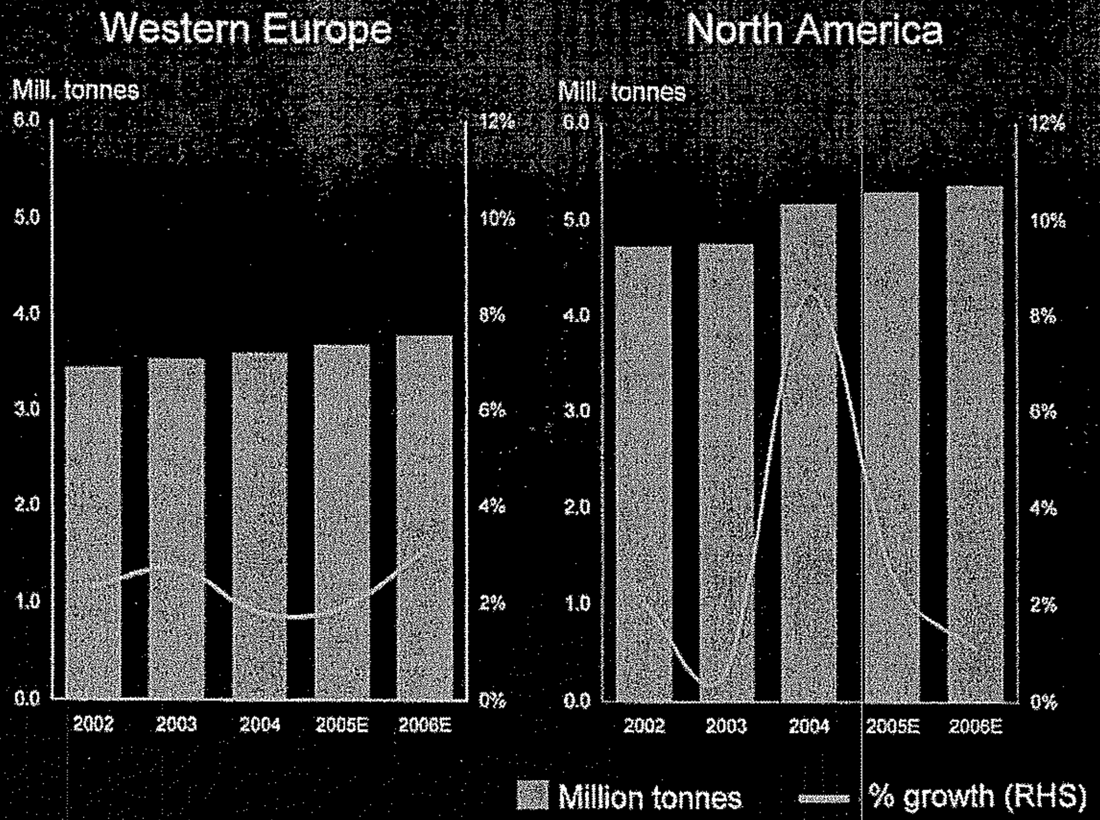
Western Europe



Source: CRU. North America includes Mexico

Rolled Products consumption

Moderate growth rates in Europe

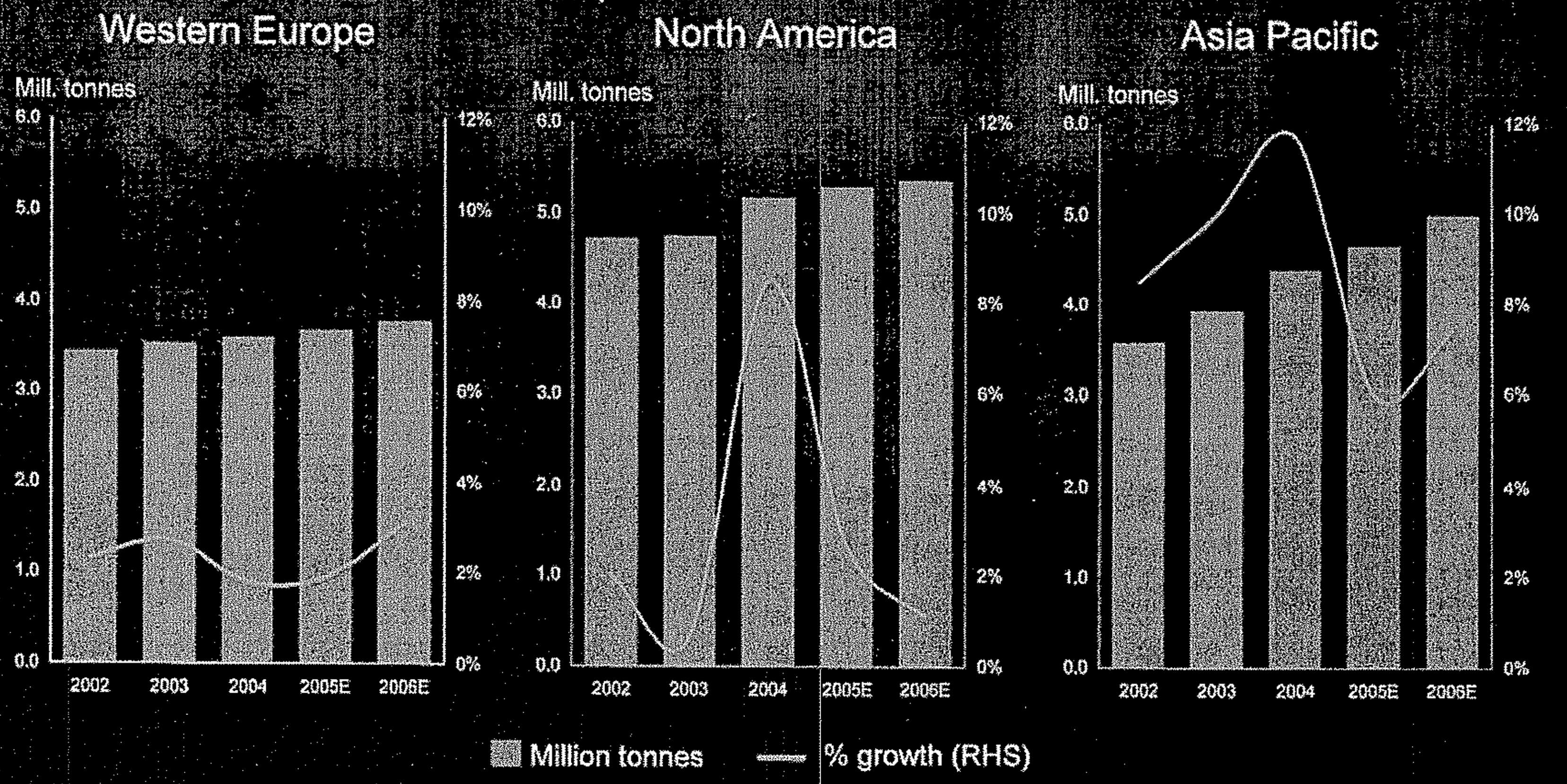


Source: CRU. North America includes Mexico

HYDRO

Rolled Products consumption

Moderate growth rates in Europe

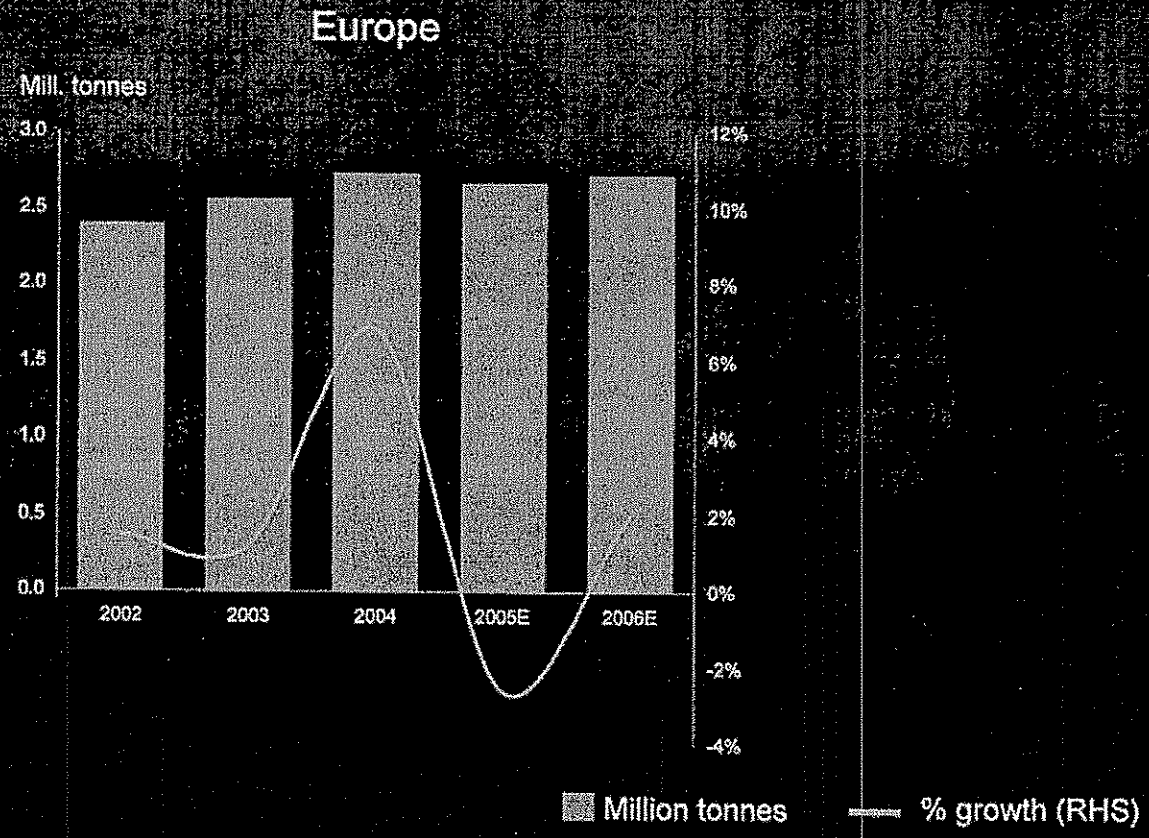


Source: CRU. North America includes Mexico

HYDRO

Extruded products consumption

Sharp correction from high growth in 2004

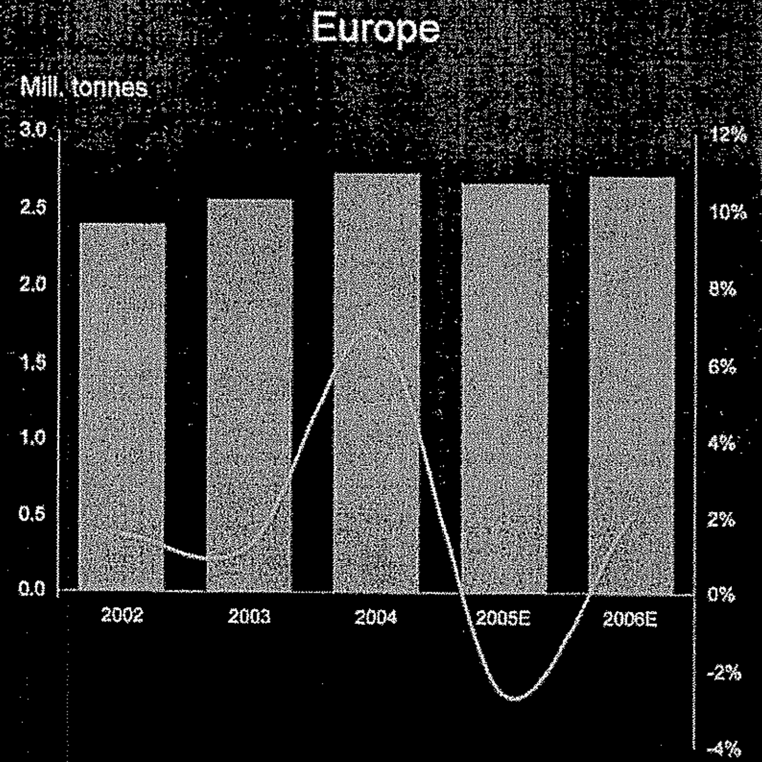


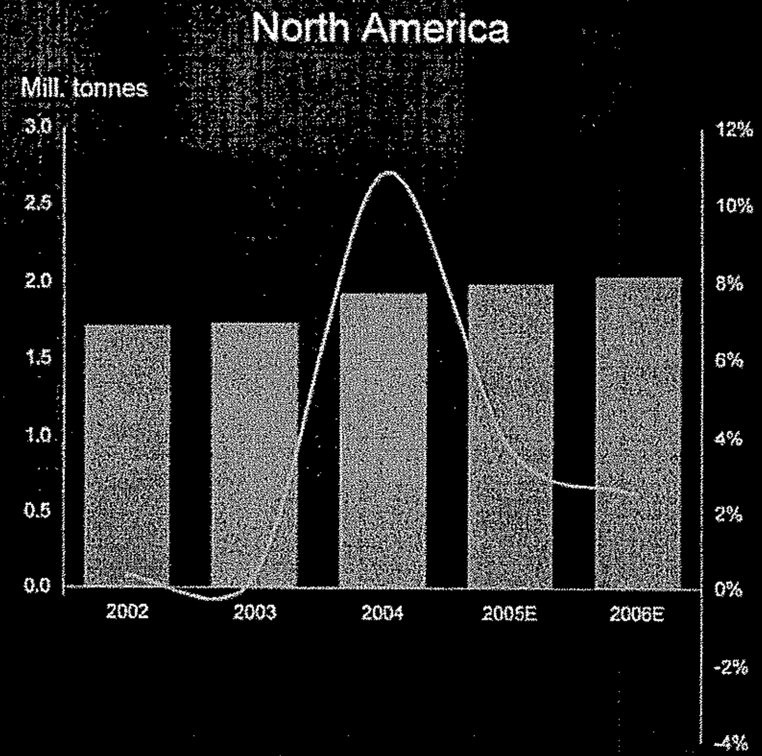
Source: EAA / Hydro (EU25 + EFTA)

HYDRO

Extruded products consumption

Sharp correction from high growth in 2004





Million tonnes — % growth (RHS)

Source: EAA / Hydro (EU25 + EFTA)

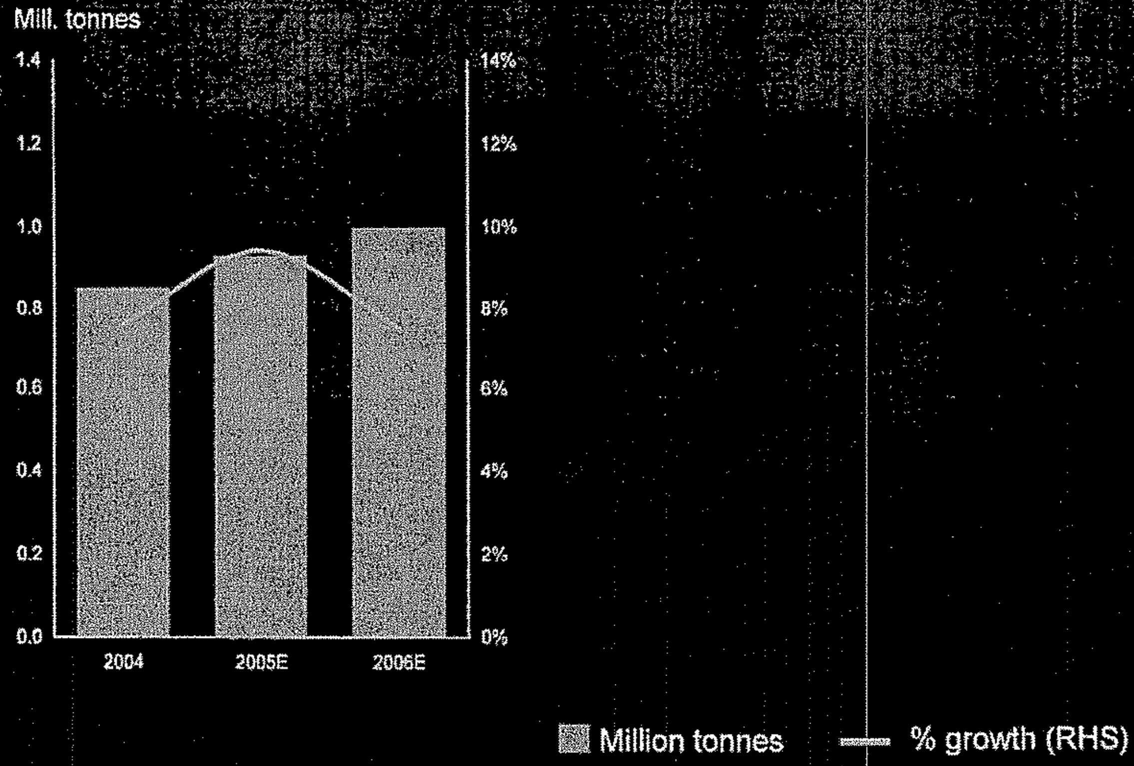
Source : Aluminum Association / Hydro

HYDRO

Primary castings consumption

Growing strongly

Europe

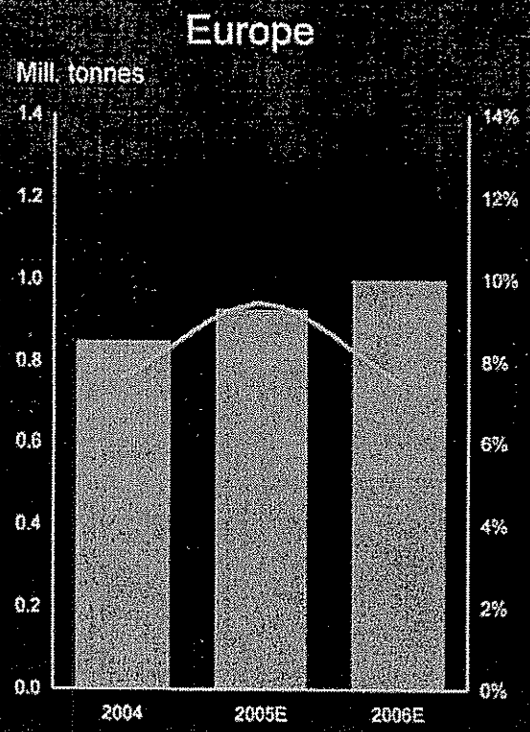


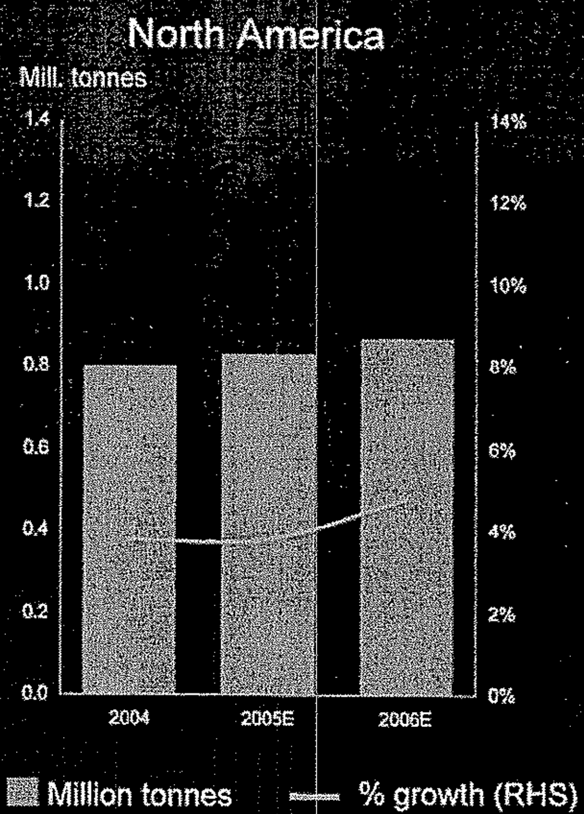
Source: Hydro

HYDRO

Primary castings consumption

Growing strongly



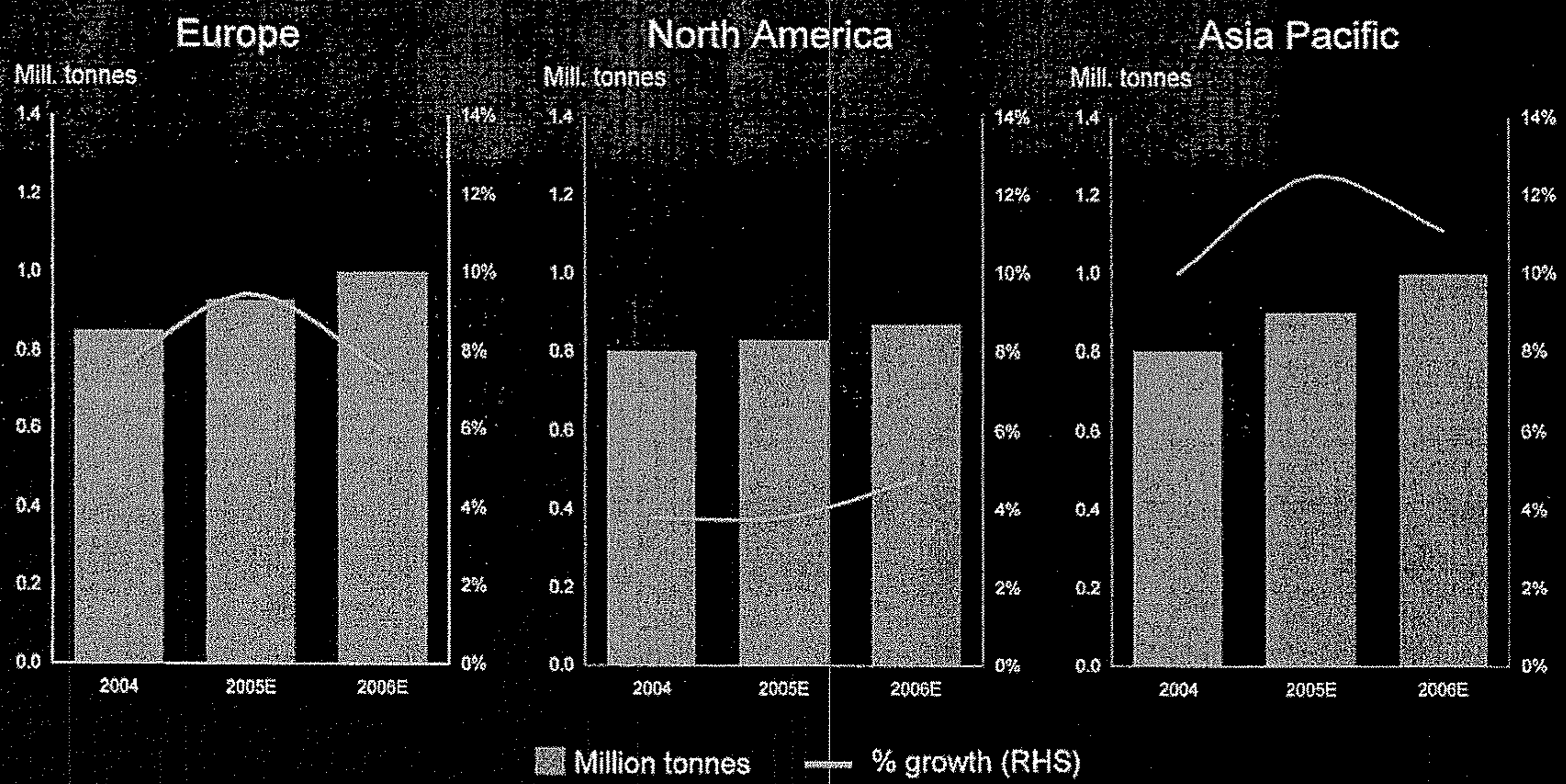


Source: Hydro

HYDRO

Primary castings consumption

Growing strongly

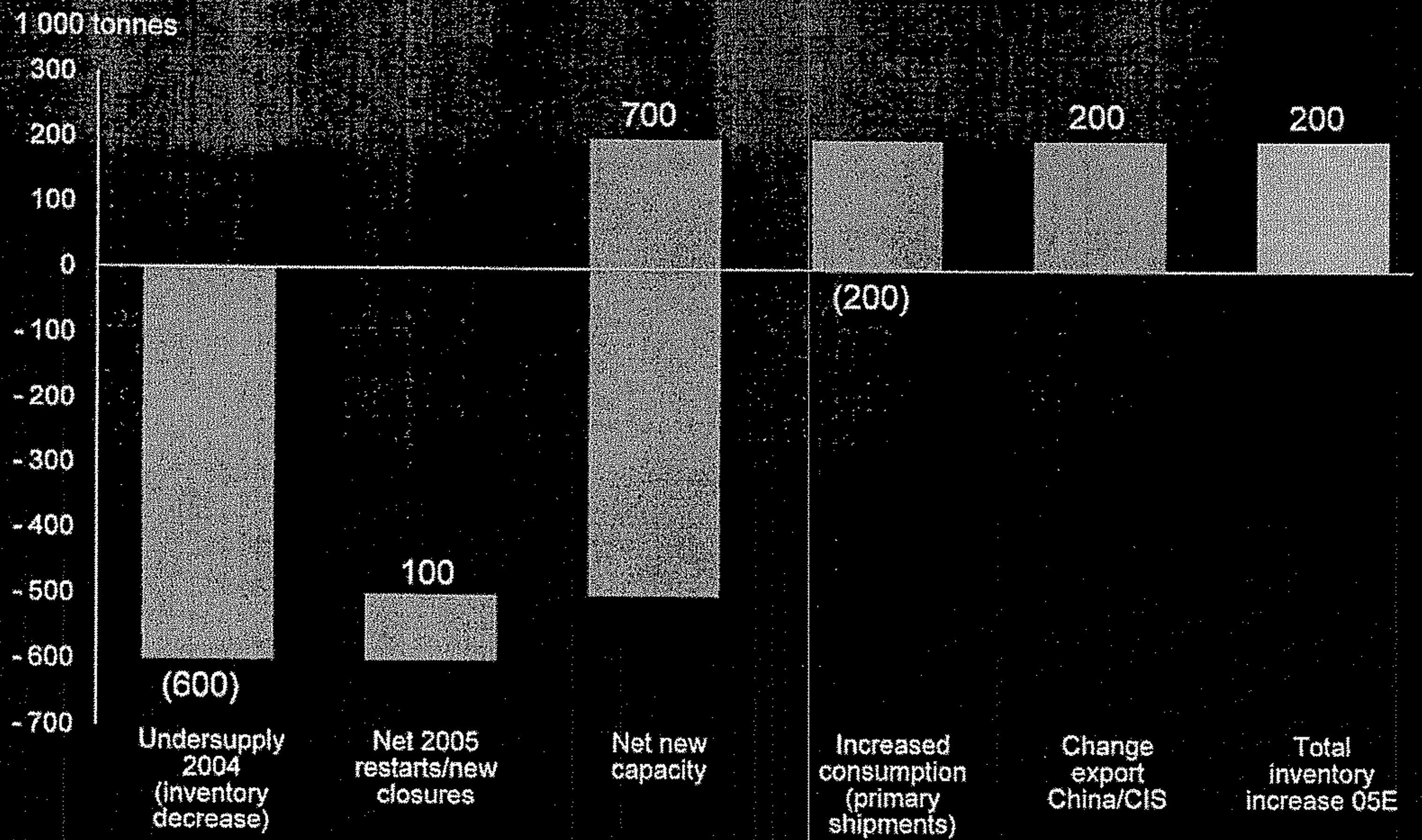


Source: Hydro

HYDRO

Primary metal balance 2005

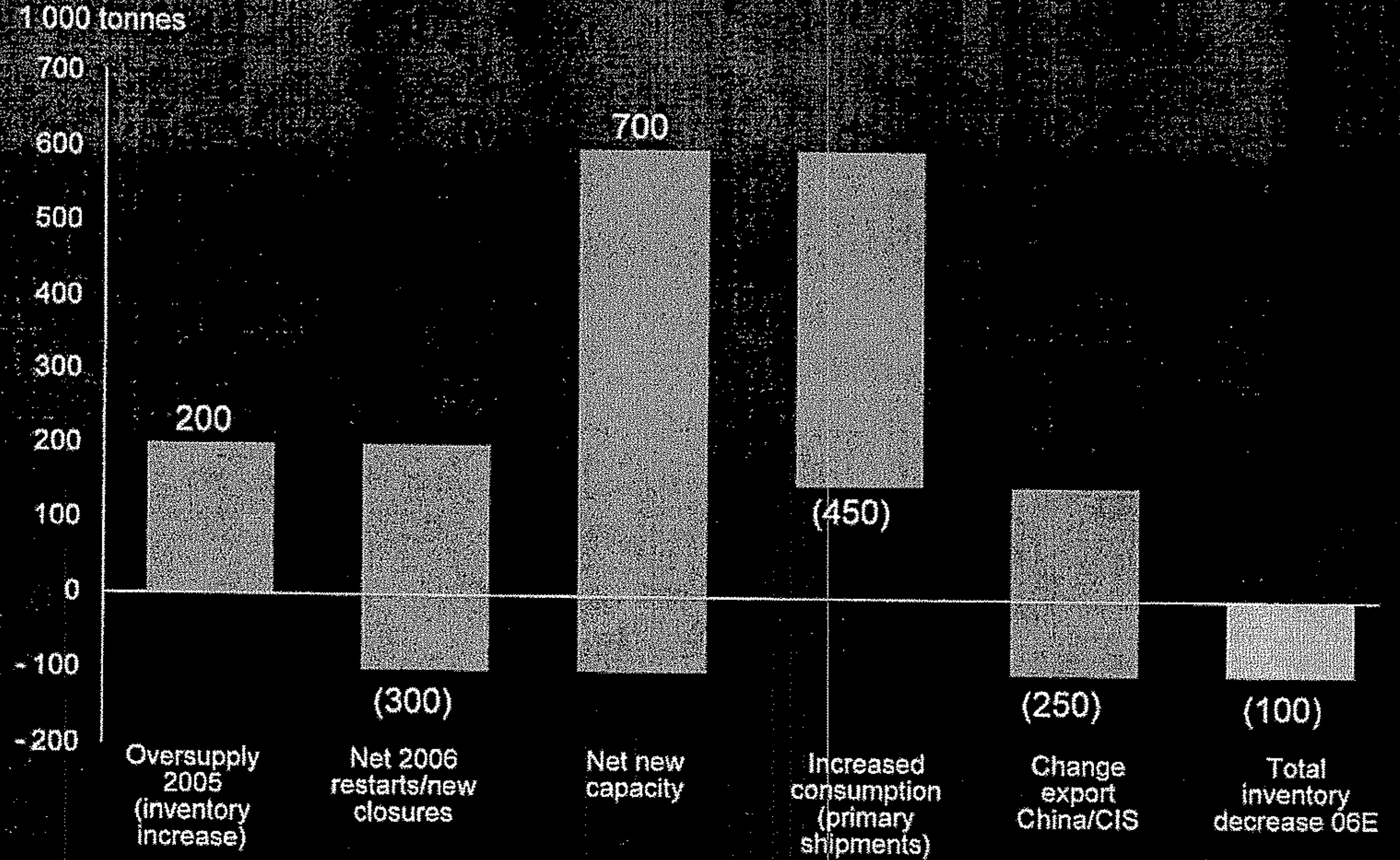
Reflects customers' inventory reduction



HYDRO

Primary metal balance 2006

Continued low inventories



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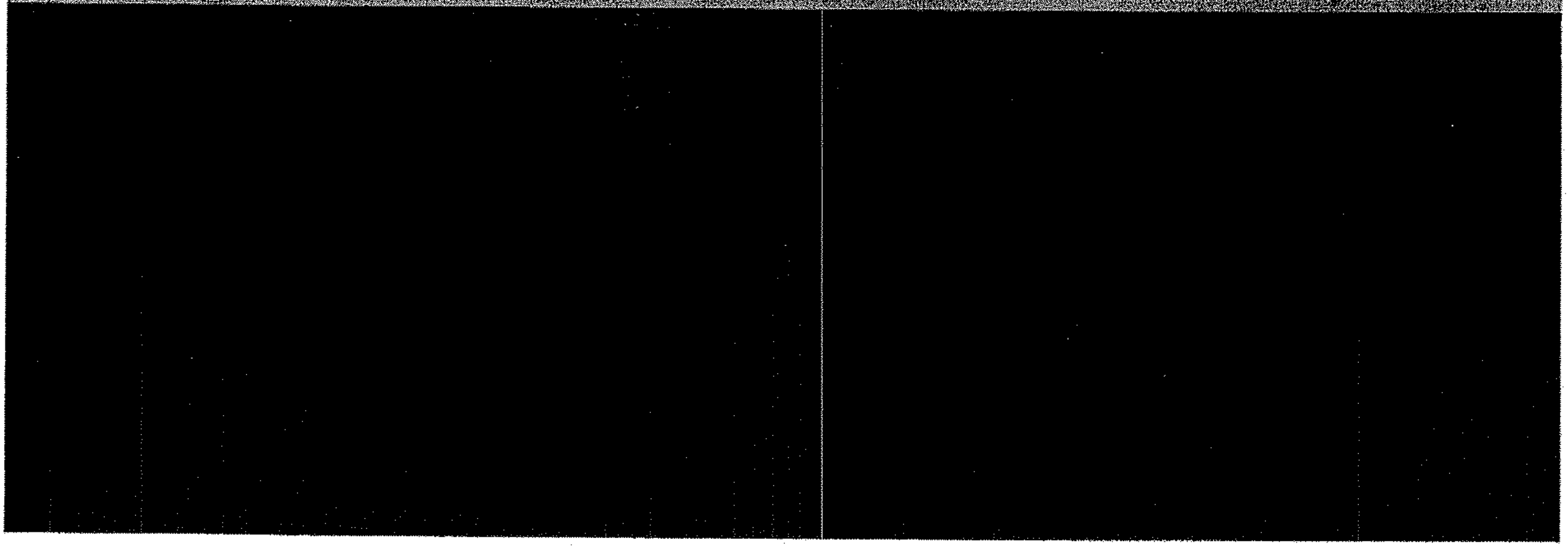
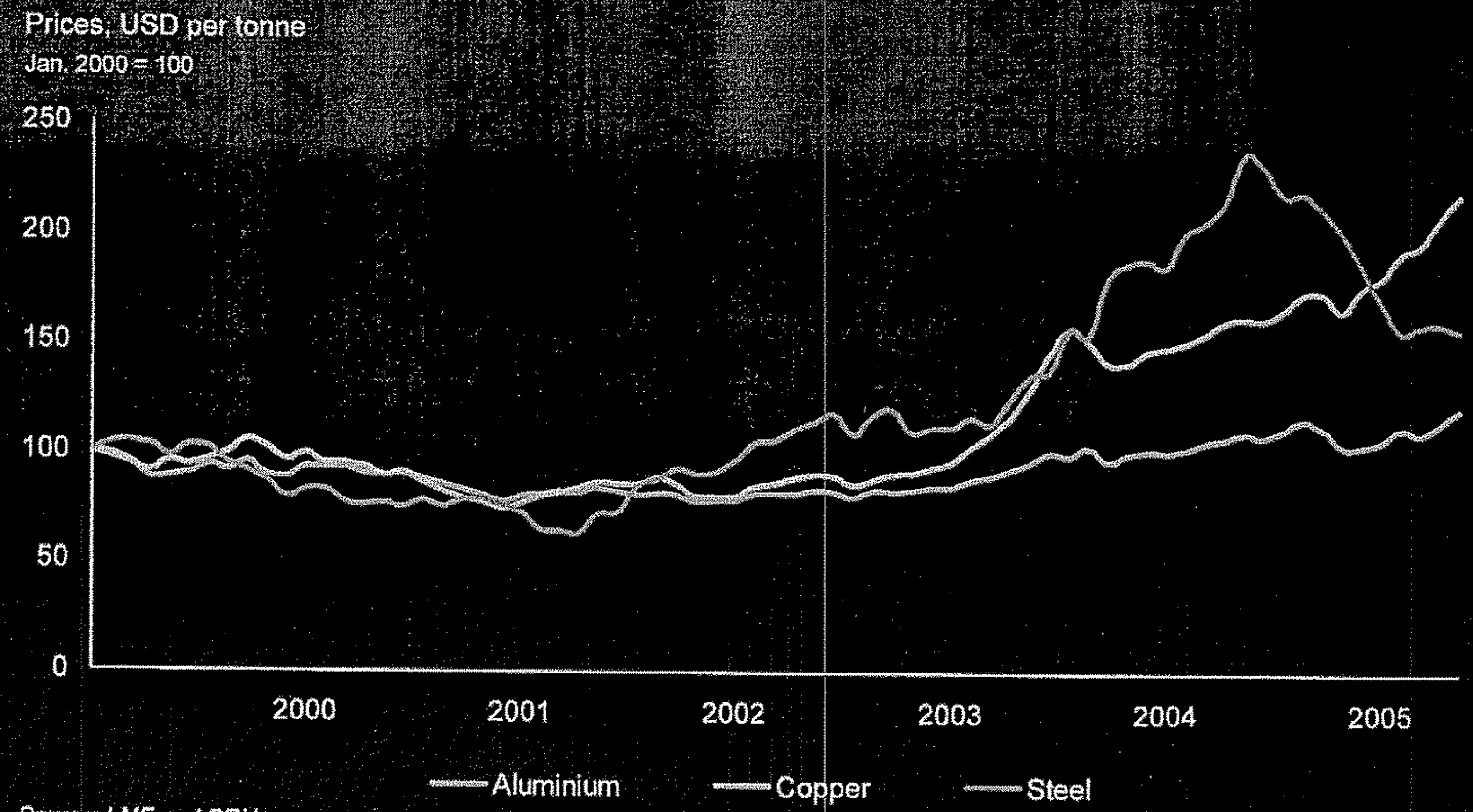
A viable society. A need. An idea. 36,000 professionals. Energy. Cooperation. Aluminium. Determination. Pushing boundaries. Respect. Nature. Courage. 100 years. Thinking ahead.

Long-term outlook



Aluminium improving relative competitiveness



Source: LME and CRU

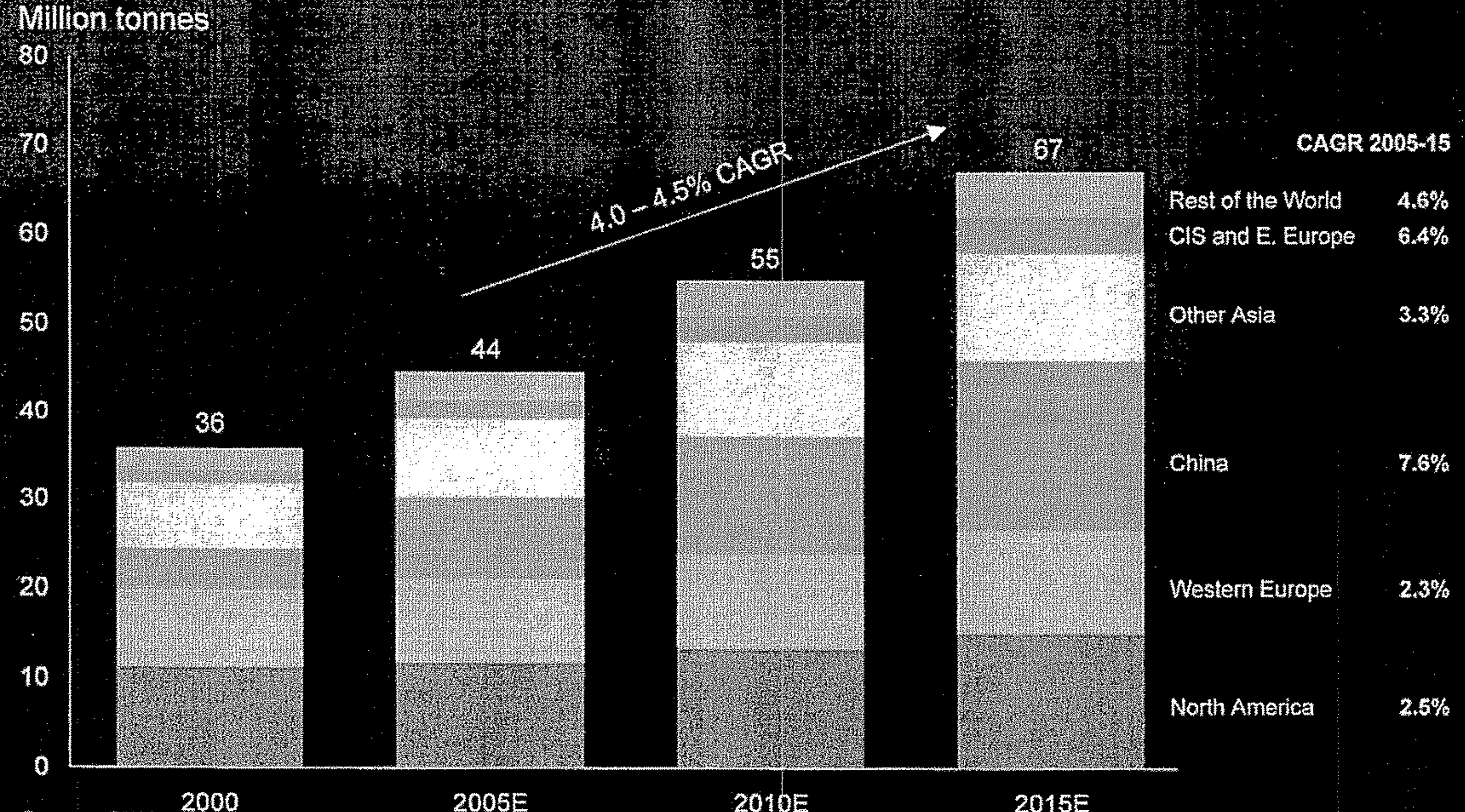
Healthy demand

- Properties give competitive edge
- Recycling friendliness becomes more important with high energy price
- Expected demand growth 4.0 - 4.5% p.a. the next ten years
- All main segments expected to grow 4.0 - 5.0% p.a. (except packaging)

HYDRO

China is leading the demand growth

Metal products consumption (primary and recycled based)

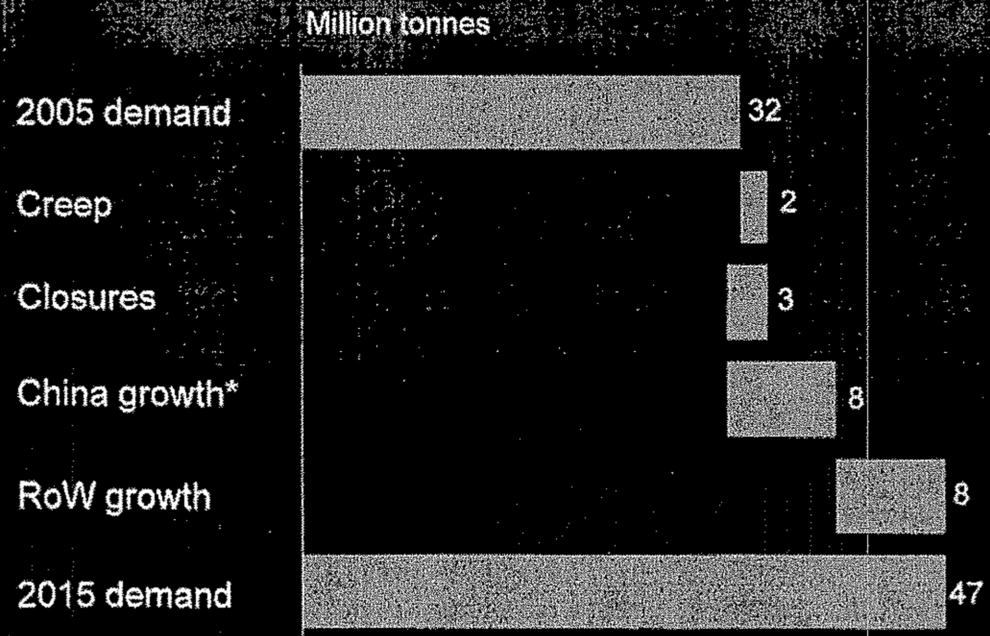


Source: CRU

HYDRO

Considerable new smelter capacity to meet demand for primary aluminium

Estimated capacity changes 2005-15



- Implies USD ~70 billion in total investments the next 10 years
- Represents ~3 new smelters annually with 500 000 tpy capacity

Sources: CRU / Hydro

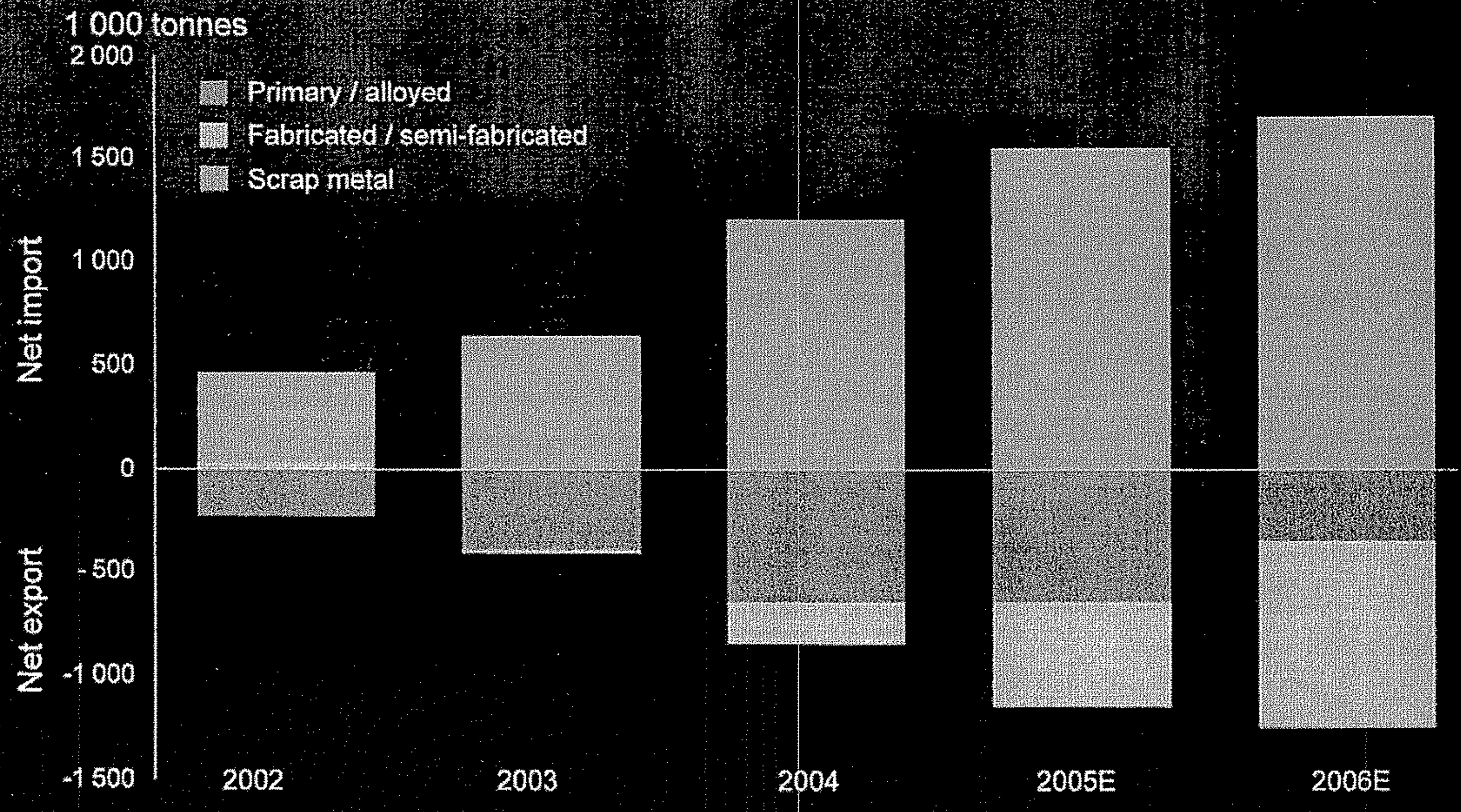
* ~2 million tonnes estimated current excess capacity not included

HYDRO

Regions with competitive energy resources

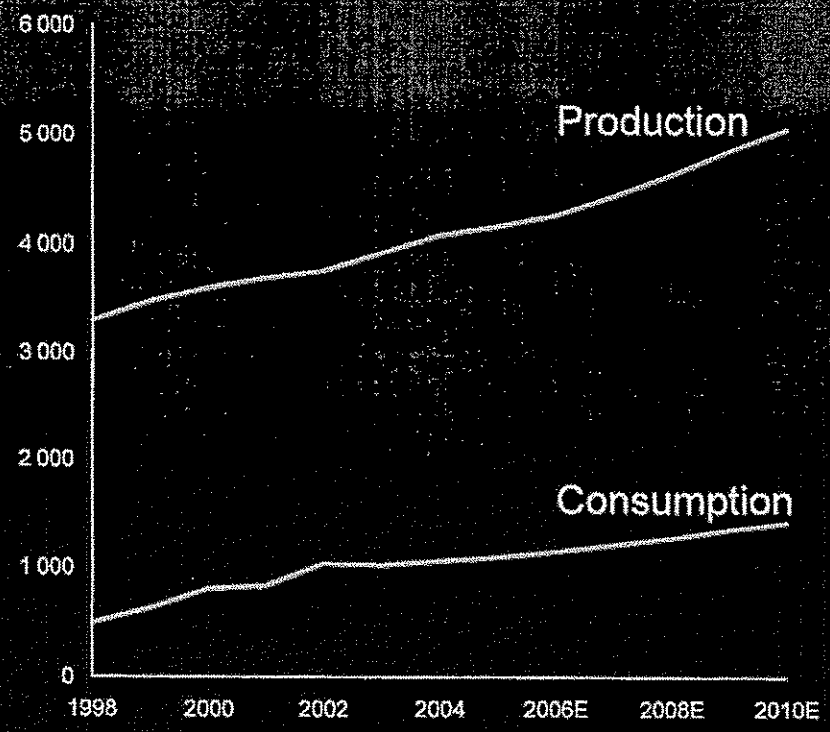
HYDRO

Changing winds from China?



Source: Antaike / Hydro

Increased export from CIS



Source: Brook Hunt / Hydro

Current supply growth drivers:

- Abundant hydro power at low cost
- Regional authorities fostering positive environment to attract and maintain industrial activity
- Rusal's ambitions

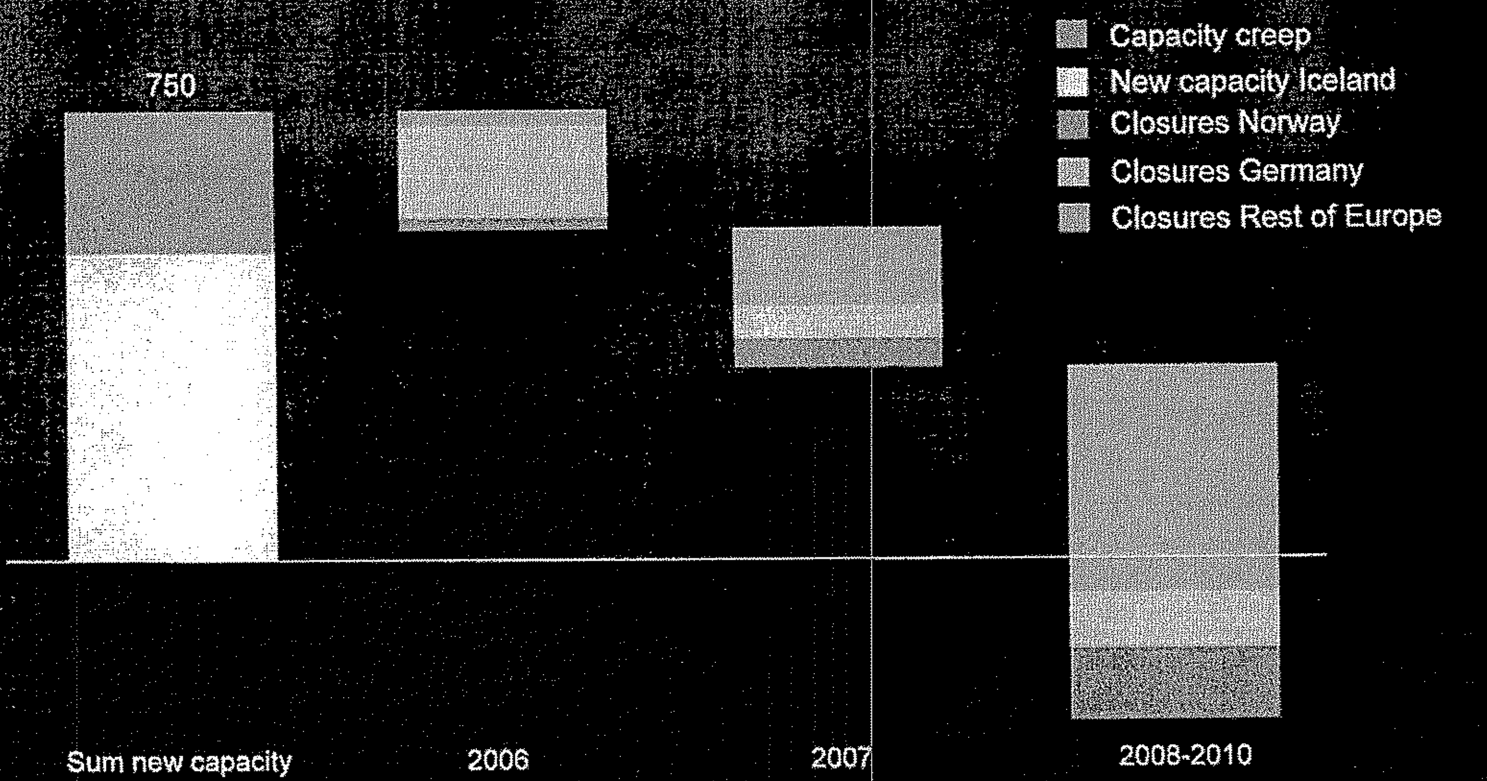
Main challenges:

- Alumina deficit
- Distance to markets
- Health, environmental and safety issues
- Large proportion of old and idle assets; need to upgrade technology

HYDRO

Possible primary capacity changes in Europe

1 000 tonnes

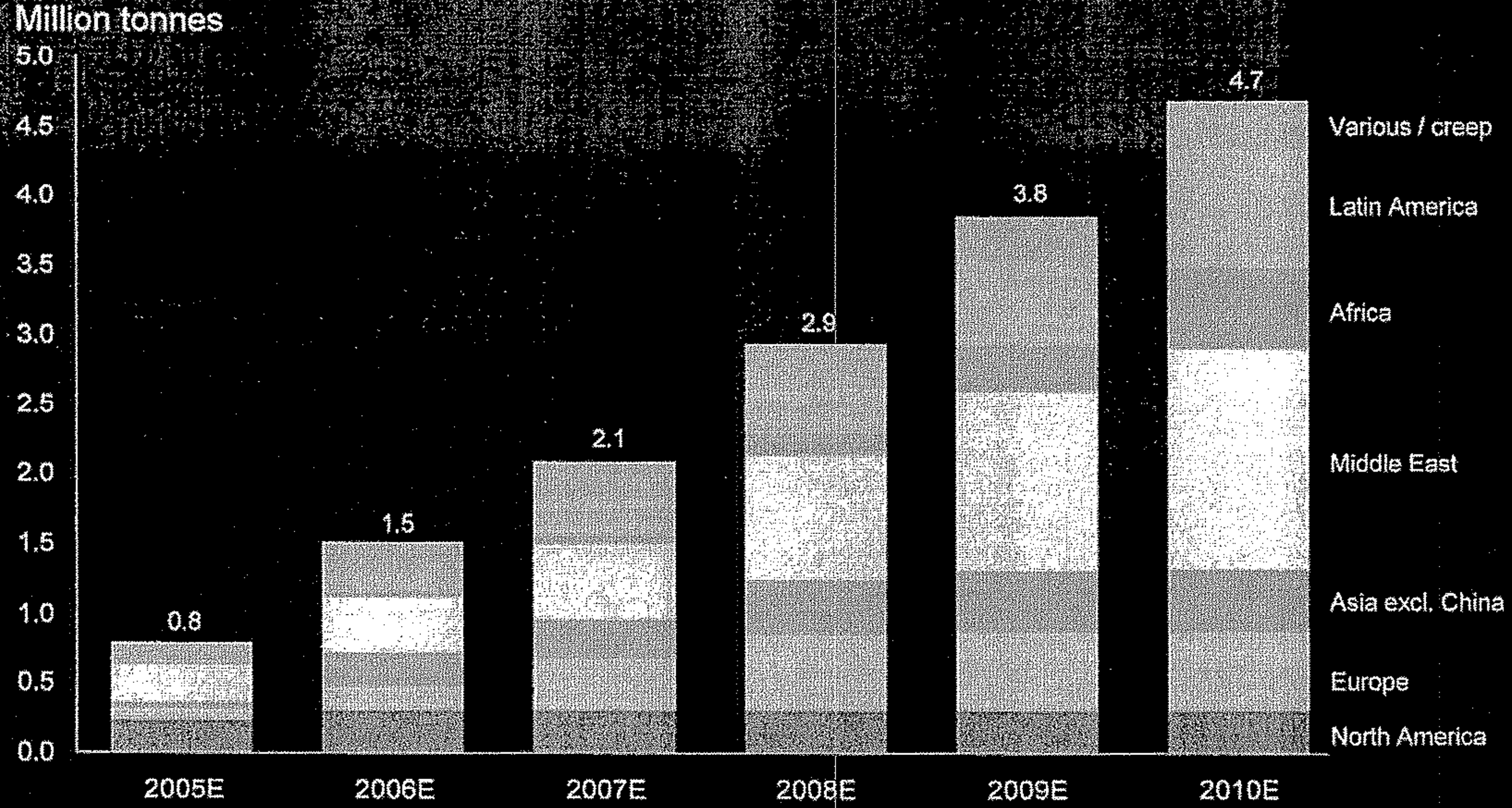


Source: Hydro / CRU

HYDRO

Middle East a key to new primary capacity

World excluding China and CIS



Source: Hydro / CRU. The figure shows estimated greenfield, brownfield and capacity creep

HYDRO

Supply development complex and demanding

- Few, energy rich areas "stranded" for the lifetime of a smelter
- State-of-the-art smelter technology ownership in few hands
- New smelters will probably be built with approximate 600 000 tpy capacity, and include development of power supply
- Countries with "complex" framework will grow in importance
  - Ownership of national resources (water, coal, gas, bauxite)
  - Engagement of national (state-controlled) companies
  - Legal framework and industrial infrastructure
  - More time-consuming planning and execution process

HYDRO

Summary

Short term:

- Healthy supply / demand balance and high production costs give support for high prices into 2006

Long-term:

- Healthy outlook for demand over next 10 years
- More time consuming and financially challenging than before to bring new greenfield capacity to market
  - Prices may support an extension of lifetime for high-cost smelters

HYDRO

BASE METALS

$1 ??/LB THIS YEAR

Yesterday's top story: Citigroup: No anticipated cyclical price spike for aluminum

While rising costs pressure should support aluminum prices at their current level for the medium term, Citigroup suggests that a cyclical spike in the aluminum price is unlikely to occur.

Author Dorothy Kosich

Posted Monday , 13 Aug 2007

RENO, NV -

In a recent analysis, Citigroup forecast that "we are unlikely to see a cyclical spike in the aluminum price that we have seen in other base metals."

Citigroup's analysis also suggests "that aluminum could remain at or around current spot levels for the foreseeable future."

In their analysis, Citigroup metals analysts Heath Jansen, Clarke Wilkins, John Hill, Craig Sainsbury, Liam Fitzpatrick, Graham Wark, Mikhail Seleznev, Meg Brown, Timothy Thein and Mark Bloomfield suggested aluminum has lagged for several reasons. These include a lack of the same supplied side constraints of other metals; a flattening cost curve; technology advancements which have lower production costs; and the availability of cheap or stranded zones of power.

Nevertheless, the analysts suggested the aforementioned factors will moderate, supporting the aluminum price in the medium term. "However, we are unlikely to see a cyclical spike in the aluminum price that we have seen in other base metals such as copper, nickel and zinc."

While Citigroup's analysis found that the trend demand for aluminum has exceeded that of copper, the underperformance of aluminum "has been driven by a lack of supply side constraints, and short lead times." While a new copper project can require a lead time of 10 years from discovery production, the analysts explained that new aluminum capacity can be added in less than two years in China, and around three years in the West.

However, aluminum industry costs have actually increased more rapidly for low-cost aluminum producers. "We now expect increased cost pressures at the top end of the cost curve as rising energy and alumina costs hit the higher end producers," Citigroup predicted.

The largest cost drivers for the international aluminum industry are energy and alumina. Energy costs represent 28% of aluminum smelting costs and 30% of the cost of producing alumina, therefore, on a combined basis, Citigroup suggested energy accounts for 40% of the cost of aluminum production. Between 2004 and 2006 the average cost of smelting aluminum increase by 9% while production increased by 15%, according to the analysts' estimates. However, these were partially offset by lower labor costs (-9%).

Emerging nations are believed to account for the majority of power generation and aluminum growth. "The primary energy mix is expected to come from coal and gas, which is very sensitive to rising fuel costs," Citigroup forecast. "Long-term power generation of 2% is expected to lag aluminum demand of greater than 4%. However, in the short-term excess power capacity in China is likely to keep a cap on power prices and facilitate further capacity additions."

Meanwhile, a rising cost curve, higher capital costs and the tightening of global energy markets "should provide support to the aluminum price," according to the analysts. Citigroup forecasts a US$1.18/lb aluminum cost this year, $1.10/lb in 2008 and 2009, $90/lb in 2010 and $89/lb for 2011. The long-term price forecast is 80-cents per pound.

Citigroup's analysts found that the top ten aluminum producers can control about 56% of the market, up from 53% in 2006. Nevertheless, "the aluminum industry has yet to consolidate to the same level as the copper industry, where the top 10 producers control around 69%. Further the aluminum industry is not as susceptible to production disruptions, such as strikes, process outings or geological events," the analysts said.

China is the world's largest aluminum producer, comprising 23% of total production last year, followed by North America at 17%, Europe at 16% and Russia at 12%. The largest increase in production between 2004 and 2006 *was 61% in China, followed by India at 30%. In the meantime, more than 90% of the aluminum now produced in* China is consumed domestically.

Citigroup forecasts that world consumption of aluminum, excluding China, to be in line with global GDP at an average growth of 2.7% versus production growth of 2.1% "In contract we expect average Chinese consumption over the next four years to average 10.4% versus production growth of 14%."

The analysts found China and Europe have the highest operating costs ($1,519/t and $1,499/t in 2006) while the rest of Asia and Africa at the bottom with costs below $1,200/t. Nonetheless, Chinese capex costs are 30-40% below that of the West.

Labor costs decreased 20% in Russia and China, but increased by 30% in South America, making it the most expensive of the developing world. Energy cost increases were the highest in South America (30%) and Russia (19%), according to the analysts.

"Over the medium term we expect energy cost pressure to persist," Citigroup said. "In the short-term we expect energy cost increases to remain low in China."

"Our Chinese power analysts expect capacity additions to exceed demand in 2007 and 2008 and then begin to reverse in 2009/10 onwards as supply growth slows," the analysts added.

Citigroup found alumina costs are highest in Europe and North America because of high energy, freight and labor costs, while the lowest costs are found in Australia due to low bauxite, freight and energy. China and Russia benefit from cheap labor costs.

Based on their analysis, Citigroup asserted that the primary energy mix for electricity generation is expected to be coal, noting that "China's dependence on coal-fired electricity generation will not change.

Citigroup suggested that the introduction of global carbon pricing schemes for emissions trading is unlikely to steepen aluminum's cost curve. Thus far, the aluminum sector has not been included in the only mandatory emissions trading scheme in the European Union.

The analysts concluded that Norsk Hydro and Alcoa are their preferred exposures globally.

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Allan Seccombe
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[miningmx.com] -- BHP Billiton was in talks with South African power utility Eskom to supply more power to its Mozal aluminium smelter in Mozambique ahead of a 250,000 tonne expansion, said Alex Vanselow, president of the group's aluminium division.

Mozal produced 551,000 tonnes of aluminium in the 2005 financial year, record output.

"We have finished a feasibility study on Mozal III and we are in discussions with Eskom and Mozambique to source power, but there's nothing at this stage that we can disclose," Vanselow told an analysts' briefing on aluminium.

The plan is to add another potline, which would increase capacity by 250,000 tonnes, he said, declining to reveal the costs because there was "still some work to be done."

There are a number of brownfield expansions projects BHP Billiton was considering to increase output, apart from employing higher amps at its existing smelters to boost production.

A proposal to increase output at the Alumar smelter in Brazil has been taken to the board for consideration. However, there are some outstanding matters to resolve with its joint venture partner, Alcoa. The plan is to raise production to 3.5 million tonnes from the current 2 million tonnes/year.

> "The market is extremely tight"

On a broader front, supplies of alumina, the raw material needed to make aluminium, are expected to remain tight over the next couple of years as demand continues to race ahead of refineries. The refineries were operating at full capacity, said Julius Matthys, BHP Billiton's aluminium division marketing director.

"The market is extremely tight and utilisation rates are at 100%," he said. "Through the whole of 2006, utilisation rates will stay at extremely high levels, which is effectively 100% of capacity."

The tight market conditions are expected to ease slightly in 2007.

Any hiccup in production would be seen instantly in prices, he said.

BHP Billiton sees primary aluminium consumption rising to 51 million tonnes per annum (mtpa) from 32 mtpa this year. Chinese demand is expected to more than double to 16 mtpa in that period.

Global use of primary aluminium will have increased fivefold from 1970 to 2015. The whole aluminium industry has a turnover of $180bn/year.

Aluminium producers, particularly those in Europe and the United States, face a tough ride, particularly because of increasing power costs as sky-high fuel prices are felt, said Rod Kinkead-Weekes, the vice-president of aluminium strategy.

"In general, what we're seeing is project delays and the supply side struggling to keep pace with demand," he said, explaining there were rising input costs of power, coke and alumina, which is made from bauxite.

Economic bauxite deposits have been consumed, he said.

"One could say the fat rabbits have been caught. The remaining resources are in more challenging countries where things move more slowly and project risk is much higher... Alumina supply will be stretched for some time," he said. The higher input costs are bad news for expensive aluminium smelters.

"It's good for (aluminium) prices, it's good for those at the bottom of the cost curve and those with locked in or hedged inputs," he said. "This will be serious for some at the top of the cost curve particularly those with expiring power contracts."

"We've already seen smelter closures in Europe and the US and there will be more to come and this is fundamentally because power prices will be structurally higher in those regions than in the past."

Matthys said an estimated 20% of EU smelting capacity has to renegotiate power contracts before the end of 2007.

Robin Bhar, a metals analyst at UBS in London, is reported by Dow Jones, to estimate that a million tonnes of European aluminium smelting capacity could be closed down because of high energy costs.

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US aluminum outlook mixed; energy prices weighing

The US aluminum market outlook is a bit mixed through next year, as both positive and negative factors might keep aluminum prices relatively stable going forward, although high energy prices are expected to weigh heavy on the market, according to key industry players and analysts. However, investment bank and London Metal Exchange ring-dealer Calyon expects a significant fall-off in aluminum prices next year by about 10¢ to around 74¢/lb.

Stephen Johnston, senior industry analyst for Canadian aluminum producer Alcan, said last week at the Aluminum Extruders Council Meeting in Chicago that a positive for aluminum prices and demand are power costs for aluminum smelters, expected to continue rising in Western Europe, the US and China, thus constraining some production. Also, alumina prices should remain high for several more months; aluminum prices have not risen as much as other base metals; the US dollar is expected to remain weak; LME stocks are low and Chinese tax changes are discouraging aluminum exports.

On the negative side, Johnston said oil prices are near record highs in real terms and threaten economic growth; the price of competing materials, such as steel, are declining; current high aluminum prices encourage startup of idled Chinese smelting capacity; and alumina prices are likely to ease over the next few years.

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Johnston said automotive demand, the biggest market for aluminum, was down 2.5% on-year for January-July, although inventories are being worked down thanks to employee pricing. Housing starts were up 6% in the first seven months of the year. Johnston said he expected a relatively balanced aluminum market in 2005 and 2006.

According to Fritz Gilbert, director of metals planning for aluminum sheet maker Novelis, speaking at the Institute of Scrap Recycling Industries meeting in Chicago, aluminum prices should average 84¢/lb in 2005 and 83.7¢ in 2006. Prices should range 82-87¢ in 2005 and 78-86¢ in 2006. LME cash prices were at $1,866/mt (84.6¢/lb) on Sep 23.

Uday Patel, senior consultant for CRU, said at the ISRI conference that global aluminum demand is expected to rise by a "healthy" 4.7% in 2005, fueled by high use in the US and developing sections of Asia. "China's appetite for aluminum continues unabated," he said. Also, European demand is reasonable, propelled by Eastern European growth. But the prospects for 2006 "have become clouded, though we expect solid growth," said Patel. US demand will eventually respond to rebuilding work in the aftermath of Hurricane Katrina while scrap availability is expected to increase sharply in the US and elsewhere and consumption should grow solidly in Europe and developing Asia. He said the main risks to his outlook were a global economic slowdown, high interest rates, loss of consumer/investor confidence and more destocking than expected.

On supply, world aluminum output is expected to climb by almost 6% in 2005, said Patel. Chinese production is racing ahead, but there's uncertainty on the horizon. He noted that production is constrained by high power prices and alumina availability. For 2006, Patel expects an increase of 5% in world production, with some restarts likely by end-2006.

Patel forecast a Western World aluminum deficit of 100,000-200,000mt in 2005 and 2006, compared with a deficit of almost 400,000mt in 2004. "Yes, consumption has slowed, but production is not up by as much as expected," he said, noting that "developments in Chinese trade will be critical," as a sharp slowdown in exports could be potentially bullish for prices, as could supply cuts.

Patel expects an LME three-months aluminum price of 81-82¢ in 2005 and 2006. He said industry forecasts call for an aluminum price of 82.2¢ in 2005, with a range of 77-87¢, and 80¢ for 2006, with a range of 70-100¢. "Developments in other base metals, notably copper, will have a major bearing on the direction of aluminium prices," he said. The direction also will be influenced by the dollar.

Patel expects the world economy to grow by 3.1% in 2005 and 2006, close to long-term trends. However, he sees "increasing nervousness" over 2006 prospects and expects consumer/industrial spending to weaken and persistently high energy prices to feed inflationary pressures. Hurricane Katrina is expected to dampen the short-term US outlook, but activity in developing Asia is expected to continue to expand, and China's growth forecast is expected to remain firm. The Japanese economy is expected to grow modestly, and all signs are pointing to a reasonable pickup in short-term European growth, said Patel.

Meanwhile, according to Calyon, average aluminum prices are set to ease back for the rest of this year and into 2006 against a background of weaker global growth. "We see sentiment towards metals turning more negative as we move forward," it said in a report. "Aluminium will not be spared and our forecast is for cash prices to average $1,625/mt in 2006 versus the $1,845/mt seen in H1 2005, which should prove to be the peak in the current cycle."

In the very near term there is a sizable long position that will "most probably be liquidated," Calyon said. "Speculators have tried to catch the market out by building up positions in August 2005 and the current long could be 30-40,000 lots," Calyon said. "However, consumers remain cool in the face of higher prices and have not hit the panic button," it added, noting that the cash to three-months spread on the LME remains in contango.

"The decision facing the longs is whether or not to throw more money at the market or try and liquidate via a sneaky exit which is never that easy," said Calyon. "We suspect that total liquidation of the recently built-up position could see three-months prices fall back to the low $1,700s/mt."

On market fundamentals Calyon is forecasting a 75,000mt supply surplus in 2005 following a 400,000mt deficit in 2004, despite a 140,000mt year-to-date drop in LME stocks. "When we combine available stats with anecdotal evidence from the physical market we are happy with our conclusion leading us to believe that LME stocks are not a true reflection of the market as a whole," the report said, adding it was taking its cue from the "real" physically traded market and predictions of demand slowdown rather than extrapolating the declining trend in LME stocks.

"Producers are therefore right to sell into the strength and those who have not sold forward so far should do so before the reality of the physical market becomes all too apparent," Calyon added. On demand, "there is mounting evidence that we are now in a period of soft growth with further bias towards revisions on the down side," the report said, citing a sharp drop in

US and Chinese consumption growth (2% growth versus 11% growth and 10% versus 17%, respectively) compared with 2004.

While Europe and Japan hope for a more accommodating economic environment following elections this month, "we doubt that these two regions could or will become sentiment drivers for base metals, and thus we expect the big two (US/China) to remain dominant in terms of strategy drivers," Calyon added.

China remains a key factor in the aluminum supply-demand balance, the report said, bemoaning the lack of reliable statistics on Chinese production and consumption: "If we take the stats at face value, then China is now consuming around 22% of world aluminium," said Calyon. "This is a large and dynamic chunk of business that essentially has to be analysed by gut instinct."

Chinese aluminum exports are running well ahead of 2004 levels, the report suggested: "Exports in the year to July have already reached 520,000mt which if extrapolated suggest a full-year figure of around 890,000mt [compared with 600,000mt last year]. If the export data is right then this in part explains the cap on LME aluminium prices, ie the flood of exports from China has more than offset the decline in LME stocks, leaving markets well-supplied."

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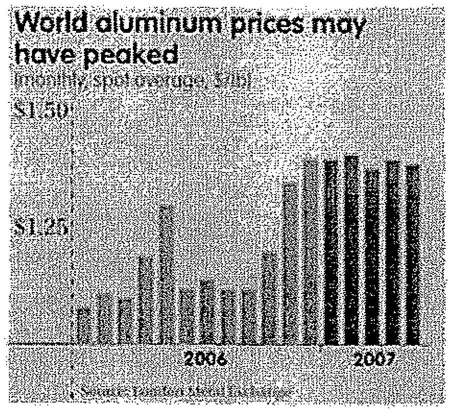
From the pages of Purchasing Magazine Online

Aluminum prices are poised to slide

By Tom Stundza -- 6/6/2007 9:02:00 AM



The slight downward trend in aluminum prices persists. And, "from the fundamental, seasonal and technical standpoint (the predictable components of this market), aluminum prices should continue to head slightly lower," forecasts Harbor Intelligence in a note to clients. Reason: World supply is expanding while demand has stalled, boosting world stocks by 4.5% over last year.

Aluminum averaged $1.39/lb in May but the research house's monthly technical indicator has given off bearish confirmation of imminent declines. Harbor Intelligence expects that today's world market price on the London Metal Exchange (LME) of $2,755/metric ton ($1.25/lb) will head toward $2,750 ($1.247) and then toward $2,720 ($1.23). This is only slightly more bullish than Davenport Equity Research's view that the world aluminum primary ingot price this year will average $2,700 ($1.22).

Aluminum prices have received downside pressure from news that Ormet has restarted its fifth potline and is planning to restart its sixth potline by September. "We should expect prices to continue to slowly trend lower for the rest of the year," says the report. "Nevertheless, prices will not fall that much given still low aluminum inventory levels in terms of weeks of consumption, a weak dollar, a bull market in nickel, lead and tin, still high copper and oil prices, and stable interest rates in the U.S."

For a midyear update on steel and nonferrous market prices, see " Metals at midyear: The bulls are still running" at http://www.purchassing.com/ on June14.

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Endurance Test for Europe's Aluminium Industry?

By Frans Bijlhouwer,
Quality Consultants, The Netherlands

I find surprising that in recent market reports on the European aluminium industry, everybody sounds positive and only talks about prosperity and growth prospects. Hardly any mention is made of the actual situation.

But in reality, when someone talks with people from within the industry itself, everyone is complaining about high costs and lack of raw materials. Who is right?

In fact both primary and secondary producers are facing significant problems of different nature.

Primary aluminium industry

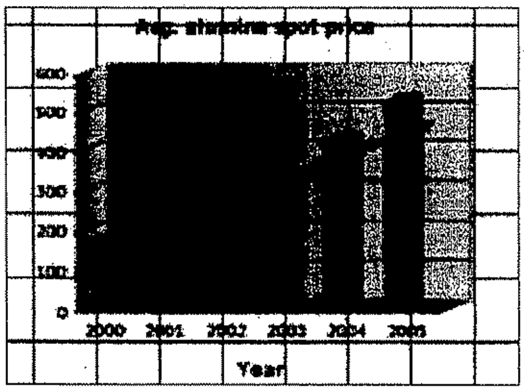
In the primary aluminium industry it is the energy costs that hurt the most.

On average, 35% of a smelter's operational cost is energy. Energy prices have sky- rocketed despite the fact that the EU expected their initiative to free the energy market in Europe would offer more competitive prices.

However, soon after the free energy market started operating we saw a 30% increase in energy costs that is creating existential problems for the metals industry. Recent surges in the price of oil have not helped stabilise energy costs. Several major operators of aluminium smelters in Europe have decided to pull out of this market now or in the near future, because the margins are too small to allow any meaningful existence.

The European smelters are trying to compete with expanding smelters in places where cost effective energy is plentiful compared to Europe. Such areas include Iceland, Scandinavia, South America, the CIS and Canada with their relatively cheap hydro power, South Africa and Australia with coal, the Middle East with almost unlimited gas and Russia with all three. We observe that new investment and capacity expansion are both taking place at primary smelters mostly in these areas.

The price of alumina in the world market is an additional cause of concern. Prices may have eased recently and some analysts expect them to soften further. But with so much new smelting capacity coming on stream soon and increasing demand for alumina in spite of new refining capacity, prices could rise strongly and subsequently push the aluminium price further up. The price for alumina in 2001 was around $150/tonne; nowadays the price has gone up to $550 and experts believe that $650 is within reach shortly. A significant fact is that 55% of China's consumed alumina is imported, while 4 years ago that share was no more than 18%. Although the capacity of alumina refiners is increasing, they can't keep pace with the expansion and the demand in the world market. Therefore a significant decrease in its price is not expected in the short term.

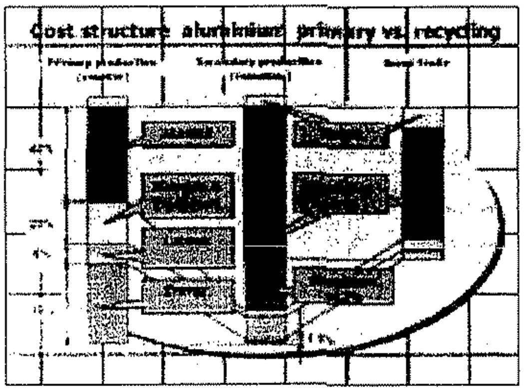


The rapidly expanding Asian countries with their 150+ primary aluminium smelters, are causing increased competition for energy and raw materials. Their pace of growth is causing problems in Europe and North America.

This means that Western Europe will no longer be able to sustain primary aluminium production and to a lesser degree, the same applies to the US. Based on such arguments, there are no strong reasons to have a primary aluminium smelter in China either. There are different reasons however to maintain activity in Western Europe, such as forward integration, infrastructure, niche markets, or the simple fact that the plant is there (and the customer too), but the profit margins will be narrowing, certainly in the longer term.

Secondary aluminium industry

This sector of the industry has always claimed low energy use at 5% of that of a primary smelter. Of course energy plays a role too, however not as critical as with primary smelters. Indeed, energy costs of secondary smelting are not the biggest problem; however the 5% claim is not entirely correct when someone counts the costs of dross and salt slag in the whole process. In reality this adds up to 12%.

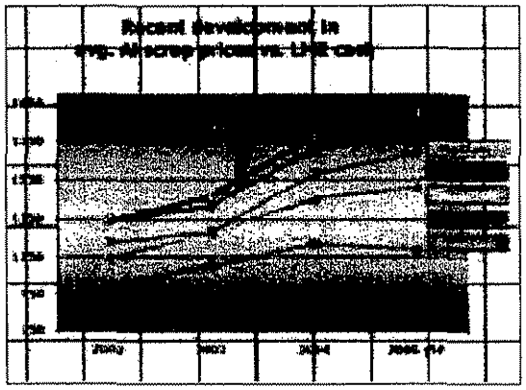


The problems in this industry sector are relating to tough competition in a shrinking market, the lack of raw materials and the high cost of labour. Not to mention legislation in acquiring raw materials, processing them and processing by-products and waste. The secondary smelting is divided into remelters and refiners. Remelters produce wrought alloys mainly from clean scrap and refiners use all kind of scrap to produce casting alloys.

The market for castings has decreased significantly due to lesser demand from their largest customer, the European automotive industry. The number of units built has gone down, some have gone bankrupt or moved away and this is felt strongly at the refiners. Competition among them is severe. According to the EAA market report of 2004 there are 123 remelters in Europe and 150 refiners. Many of them are small and subsequently their cost per tonne is too high.

At the same time the automotive industry is shifting away from Europe and North America and relocating their plants all over the world where labour is cheap. This opens opportunities for local refiners and die casters and resulting in work flows away from Europe.

The increasing presence of Asian car manufacturers in Europe does not help because they also buy parts from Asian suppliers.



The availability of scrap is under pressure. With Asia expanding so does it's secondary industry. Europe is losing large volume of manufacturing to Asia every year and this keeps high pressure on prices and is squeezing the margins even further. The scrap deficit will deepen in the next few years.

On top of that, the EU has classified aluminium scrap as waste instead of raw material. This means red tape that increases the cost of treatment and transportation.

Labour cost in Europe is one of the highest in the world. This affects the secondary industry more than the primary industry because this part of the industry is more labour intensive.

The remelters, who are producers of wrought alloys such as slab and billets, are doing reasonably well. Of course they have the same problems with energy, labour costs and scrap availability, but their market is still pretty strong and there are no signs of weakening. Many of them are forwards integrated in large global operating organisations.

The currently high and increasing metal prices are increasing the risk of substitution to other more cost effective materials.

Is there a future for Europe's aluminium industry?

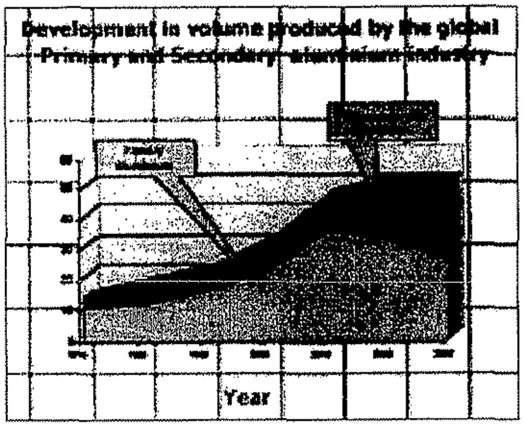
As long as energy prices are high and on the increase, we will see that operators of primary smelters one after the other will shut down their operations. The EU should have acted long time ago.

So far there have been preliminary discussions only but no action.

The loss of the primary industry in Europe will cause loss of capital and large number of jobs with unavoidable effects to the EU economies.

But it will not affect the downstream industry because the aluminium industry is global and metal can be acquired everywhere at market price, even if Europe might not have its own primary industry any longer.

On the other hand, this opens opportunities for the total restructuring of the secondary aluminium industry. This is a must.

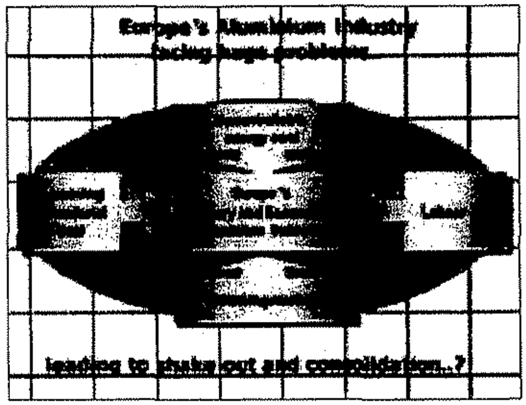


Europe requires a strong and pro-active secondary aluminium industry consisting of both refiners and remelters, to recycle aluminium and be the main supplier of the European industry.

The GARC initiative has estimated that the global aluminium inventory is roughly 515 million tonnes, the "metal bank" as some people call it. Our own research leads to an even larger figure of 650 million tonnes of post consumer scrap that will become available in the next decades to the aluminium scrap market.

This metal is presently in use in buildings, cars, packaging, planes, ships and many other applications and has not reached the end of its life yet. To handle successfully this precious source of material as it becomes available in time we must put in place an adequate operating secondary aluminium industry for such enormous volumes of post consumer scrap. This quantity is on top of process scrap that the process industry produces daily.

The European secondary aluminium industry is presently fragmented and in no position to handle this task efficiently and profitably. The need will arise soon for strong integrated organisations that are backwards integrated in the collection of post consumer and process scrap, equipped with modern sorting systems, able to process the scrap efficiently and supply the European industry with the semis it needs, such as casting alloys, forgings, billets and slabs. Most likely they will be forwards integrated in rolling, extrusion and forging.



This simply indicates that the industry is on the brink of a large-scale consolidation, not only in processing plants but also among scrap collectors and dealers. No doubt the large integrated aluminium companies who announced several years ago their intention to reinforce their activities on the recycling market, will play an important role in such shake-out and restructuring.

Such consolidation will solve environmental issues. The increased size of operations to above the critical mass of approximately 50.000 tpa, will increase profitability. This will ensure long term viability and enable investment in new technologies to optimise the scrap sorting and recycling process and revive the industry. The existing high labour costs will become less of a problem due to this consolidation and improved margins. Areas with lower labour costs within Europe and nearby exist and as they are in the vicinity of Europe they are controllable.

After all, secondary aluminium is the next best alternative to primary aluminium. **APT**

Biography

Frans Bijlhouwer has been MD at Alumax Recycling, KBM Affilips and VP of Ampco Metal, before setting up Quality Consultants in the Netherlands. His consultancy is operating in the global non-ferrous market, specialising in strategy development, marketing issues and optimising results.

the ringsider
LONDON METAL EXCHANGE

Growing energy costs remain a hidden problem for the base metals sector

The issue of rising production costs in the base metals sector has been much talked about, with high energy prices the lead topic of discussion. Nevertheless, among the many influences on the price of industrial metals, their effect has been dwarfed by powerful factors on the demand side.

The rising cost of oil and power are certainly pushing up production costs for metals producers, but the effect is one of many that producers face, not least of which is labour cost.

However, in the aluminium market the issue of rising energy costs has started to become clear, providing an indicator for other metals, should the current cycle of high prices start to turn itself around.

"If you break down copper production costs, energy only accounts for around 14 per cent, whereas for aluminium, which basically means smelters, it is 30 per cent," says Robin Bhar, metals analyst at UBS in London. "So energy costs are in the mix for determining base metals prices, but particularly for aluminium, where it is probably a key factor, and energy prices are likely to remain high."

In the aluminium market, there have already been instances of smelters cutting back or ceasing production of primary metal as a result of high energy costs. Plants have closed in the US, and more recently Alcoa announced that it would curtail production at its Eastalco smelter in Frederick, Maryland, on 19 December because it had not been able to secure a competitive new power supply for the facility.

Other smelters may follow suit as long-term power supply contracts come up for renewal, as will happen for many plants in Europe from the second half of 2006.

"Smelters renewing power supply contracts might see them negotiated 30 per cent or 40 per cent higher," says Bhar. "Also, in Europe some countries are carbon emitters, which skews the power tariff. That could mean twice the worry for countries like Germany and the UK, which could receive penalties under the Kyoto treaty, so essentially their energy costs will be higher still."

Bhar has highlighted Alcan's Lannemezan smelter in France, and its Steg smelter in Switzerland as vulnerable, along with Alcoa's Hamburg facility, Norway's Norsk-Hydro, Anglo-Dutch Corus Group's smelter in the Netherlands and its Voerde smelter in Germany, among others.

"As contracts come up for renegotiation a few smelters in Europe and the US are vulnerable to closure if they don't manage to secure attractive long-term contracts," agrees Barclays Capital's Ingrid Sternby.

The relocation of smelting capacity to cheaper regions like the Middle East or Southern Africa - or the increasing use of hydropower where possible - is likely as a result of higher energy prices.

"The Middle East has abundant natural gas and oil, so new aluminium plants are likely to migrate there," says Bhar. "Aluminium smelters ideally need high aluminium prices and low energy prices. When we saw smelter closures in the Pacific Northwest it was because energy prices were high and aluminium prices were low at around $1400/t. They need aluminium prices to be around $2500/t to be profitable, so they are likely to stay closed."

There are even instances where facilities have found it more profitable to cease aluminium production and sell on power at a premium, essentially becoming power plants.

Yet the true impact of the emerging problem in aluminium is still hidden in other metals, where prices remain relatively high. Should these prices fall, the energy price squeeze could be seen more starkly in other markets.

"At the moment we are at the peak of the metals cycle, so energy prices don't matter too much. In two, three or four years' time, when metal is oversupplied, high energy prices would put up the price floor of metals," says Peter Kettle, research director at the Commodities Research Unit (CRU).

"Energy prices would be a problem if metals prices fell, as producers are already seeing their margins squeezed, depending on their raw materials arrangements," says BarCap's Sternby. "This has been highlighted by many companies in terms of labour, steel - for which prices are relatively high - and a lack of mining equipment."

Pressure on producers' raw materials costs comes from many fronts, which has also masked the impact of energy prices, but when the metals markets move into oversupply and prices start to fall, energy cost pressure on margins will truly become apparent.

Jim Banks
LME Ringsider Newsletter
Edition 3, Winter 2005

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Metals & Mining

By Robert McNatt

t might look like the party is over in some sectors of the metals and mining world, where falling prices in recent months have raised questions about producers' long-term prospects and credit quality. But Standard & Poor's Ratings Services believes the essential message is that healthy fundamentals should remain in place for at least the next couple of years, and will sustain prices at levels that offset rising costs and serve to maintain or even improve credit quality.

We expected the decline in the price of some base metals. The lofty perches they attained were not supported by underlying supply and demand fundamentals, but rather by speculation and unfounded exuberance among traders and commodity funds, which pushed prices well beyond forecast levels to historical highs. "No question commodity prices have lost some of their luster," says Thomas Watters, credit analyst at Standard & Poor's. "However, there needed to be some weeding out of the speculative trading that had been occurring. Eventually, prices need to reflect cyclical macro economic issues and supply/demand fundamentals."

There is no doubt a benign fundamental shift in the supply/demand curve has occurred, particularly on the demand side. The economic powerhouse that is China has been the chief impetus behind the rally in base metal prices over the past couple of years. This fundamental shift should remain in place for the next several years, at least, and help sustain prices favorable for credit quality. "We believe the average price curves for the next five years should be meaningfully higher than they were for the prior five years ending 2004," says Mr. Watters. "That should offset rising cost profiles for many of these producers and help maintain a stable to positive credit quality outlook. The key rating factors going forward will be how companies utilize cash flow and the cash that could potentially be built up."

Copper: Still Strong, But Sliding Off Its Highs

While copper has returned to earth from its record price of $4.075 per pound last May, the current price of $2.45 per pound still remains well above historical highs. Supply disruptions and speculative demand had combined to accelerate copper prices way beyond appropriate levels. The sell off over the past several months has reflected a gradual increase in supply, a decline in the U.S. housing markets, softer global demand (copper demand mirrors economic growth), and destocking, which led to a decline in Chinese imports of refined copper in the second half of 2006.

Nevertheless, we remain positive on copper's near- to medium-term prospects. The Chinese economy should remain healthy and few, if any, large-scale projects are coming on stream over the next two years. Also, much of the new production slated to come on line starting in 2008 will be in politically unstable countries, and long-term supply fundamentals may be buffered by the risks of operating in such challenging regions. Moreover, rising power, environmental, and labor costs, along with declining ore grades, could force higher cost producers to curtail production. "We would be hard pressed to imagine copper prices ever reaching 60 cents to 70 cents per pound territory anytime soon," said Mr. Watters.

Aluminum: Late To The Party, But Going Strong For Now

While other metals prices rocketed to unsustainable levels, aluminum never really seemed to launch from the pad—until recently that is. After closing at $1.03 per pound on Jan. 2, 2006, aluminum touched a high of $1.34 per pound on Jan. 24, 2007. While some other base metal prices have declined meaningfully, aluminum has lingered near this level, closing at $1.28 per pound in recent trading, despite softening demand from end markets.

Going forward, however, we do believe that the price of aluminum will follow suit with other base metal prices and begin to fall. The chief proponent supporting this notion has been the rapid decline in alumina prices to about $250 per metric ton from approximately $650 per metric ton early in the year, a decline spurred on by a 60% increase in Chinese alumina capacity. The question remains how quickly China, given access to this cheap alumina, will be tempted to ramp up its idled aluminum production and shift the market into a surplus. China continues to ramp up its smelters, with estimates of total smelter production in 2007 of 11.1 million metric tons. As opposed to 2006, when aluminum demand outstripped supply and pushed up prices, an augmenting aluminum supply in 2007 will most likely swing the market into a surplus.

The credit quality of primary aluminum companies is also challenged by the escalation in energy costs over the past few years. The cost of moving production to regions with lower energy costs can be substantial. Indeed, on Jan. 19, 2007, Standard & Poor's lowered its ratings on Alcoa Inc. to 'BBB+' from 'A-', reflecting these very concerns.

Nickel: Prices That Seem To Defy Gravity

Nickel continues to stump market pundits with its recent lofty price tag of $17.15 per pound. Although it had participated in the base metal rally, its has left its brethren behind, reaching record prices in the low-$19 per pound area in late-January 2007, from a low of $6.86 per pound in early September 2005. Standard & Poor's believes the outlook for nickel through 2007 remains highly favorable, as London Metal Exchange inventories remain at about only one day of global consumption. Stainless steel production—a key driver of nickel prices—remains strong, and fundamental supply constraints should limit downward pressure on nickel prices. Nevertheless, there is concern about demand, with some stainless steel producers shifting to lower grade nickel in response to high prices.

In terms of supply, the most significant new mine, CVRD Inco's Voisey's Bay, should be fully ramped up in 2007, bringing into production 50,000 tonnes of nickel per year, or about 4% of global output. Meanwhile, BHP Billiton PLC's (A+/Stable/A-1) 50,000-tonne Ravensthorpe project has been delayed until early 2008 at the earliest, from mid-2007, while CVRD Inco's 60,000-tonne Goro project has been delayed at least one year until late 2008. The sheer scale of these operations, combined with smaller increases in output from brownfield expansions elsewhere, could move the nickel market into a surplus in 2009. But all these projects are facing markedly higher capital costs and potential delays in achieving commercial production, which should maintain the tight supply/demand balance in nickel through 2008.

The rash of consolidations and M&A mania that has been sweeping the metal and mining industries has not excluded steel.

Steel: Pricing Taking A Breather

Although steel prices have ebbed somewhat, they remain robust compared with historical levels, and good for credit quality. Steel prices were pressured in the second half of 2006 because of cooling demand from end-users, rising imports, and increased inventories, especially for flat-rolled products. Steel service centers and producers, however, have made concerted efforts to rein in the inventory overhang and lower production, which should establish a price floor and allow for a gradual price increase by the end of 2007.

The rash of consolidations and M&A mania that has been sweeping the metal and mining industries has not excluded steel. The U.S. steel industry has undergone a transformation since the tragic events of Sept. 11, 2001, after which it suffered numerous bankruptcies brought on by record-low prices. Indeed, in North America, the top three U.S. producers now account for over 61% of total production. Most notably, the $33.1 billion merger between Arcelor S.A. (BBB/Stable/A-2) and Mittal Steel Co. N.V. (BBB/Stable/—) in 2006, created the world's largest steel company.

Standard & Poor's believes the consolidation in the domestic market has improved production discipline and added cost competitiveness, which should lead to less volatile prices as producers idle capacity to match demand. Furthermore, industry consolidation and favorable conditions have allowed steel companies to continue to benefit from the surcharge mechanisms, successfully implemented in 2004, that enable them to pass on rapidly increasing raw material and input costs, particularly for scrap.

Nevertheless, for the longer term, we remain concerned about increasing global capacity. "The history of steel imports in the U.S. has taught us a valuable lesson and that is steel is a globally traded commodity. Foreign governments in the past have subsidized money losing operations to keep the mills running and labor employed," said Mr. Watters. "As such, the domestic industry will remain under the constant threat of imports." The significant, ongoing ramp-up in steel production in China, Brazil, and Russia, especially in flat-rolled products, raises the specter that this additional output could ultimately find its way back to North America in the event of an economic slowdown in these regions. That would intensify competition and volatility.

Moreover, the U.S. is now the third-largest steel-producing country, and accounted for 8% of worldwide production in 2005, compared with 31% from China, the largest steel producer. Chinese steel capacity increased an incredible 177% from 2000 to 2005, while U.S. capacity decreased 6% during that time.

Coal: Prices Falling Down The Chute?

While coal is not considered a true commodity, spot prices over the past couple of years have certainly behaved like a commodity. Coal prices have retreated significantly since early 2006, a result of a slowing domestic economy, declining prices for competing fuels, and unseasonable weather patterns. "On the whole, however, we see moderation, not disaster, in coal prices going forward," said Mr. Watters. "Coal's position in the domestic energy spectrum is well entrenched with abundant reserves and its lower cost versus other competing fuels. Its potential to be used as an alternative fuel source also supports this thesis. Longer term fundamentals remain intact and should be supportive of coal prices."

However, we believe not all coal producers will enjoy the party. Credit quality for Central Appalachia coal producers remains largely negative, given the many issues faced by producers in that region. Extremely difficult geologic and operating conditions, an inexperienced labor force, legacy liabilities, and onerous permitting issues have combined to sharply increase operating costs, rendering many Central Appalachia producers insolvent. Moreover, utilities concerned about the long-term viability of this region's producers could turn to coal from Northern Appalachia, the Illinois Basin, or the Powder River Basin (the three other main coal producing areas in the U.S.), leaving Central Appalachia producers to face pricing pressure and a classic margin squeeze. Needless to say, Central Appalachia coal producers rated by Standard & Poor's are at the low end of the credit spectrum. **CW**

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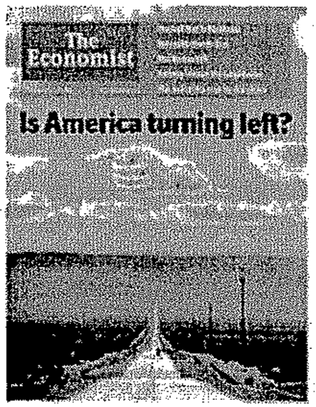


Business

Aluminium

Gimme smelter

Jul 19th 2007

From *The Economist* print edition

Are more big deals ahead?

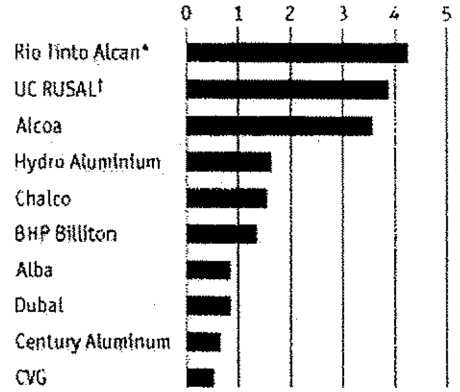
THE notion that aluminium is merely a dull, grey metal has taken something of a hammering lately. A dramatic string of mergers, bids and counterbids has enlivened an industry that is proving to be as malleable as its end product. On July 12th Rio Tinto, one of the world's biggest mining firms, comprehensively trumped Alcoa's hostile $27 billion offer for Alcan, a Canadian rival, by stumping up $38.1 billion in cash. The deal will make Rio Tinto the world's top aluminium producer (see chart), ahead of Russia's RUSAL, which was itself involved in a big merger in March. And the flurry of activity in the industry might even result in Alcoa itself being gobbled up. BHP Billiton, an Anglo-Australian mining giant sitting on a pile of money earned from high metal prices, is thought to be mulling a $40 billion bid for the American aluminium-maker.

What explains all this dealmaking? Tom Albanese, Rio Tinto's boss, is confident that the huge sum he is paying for Alcan is justified, in large part because of the situation in China. It is expected to consume 12.5m tonnes of aluminium this year out of a world total of 40m tonnes. But although Chinese demand has pushed up the

Forged aluminium

World's top aluminium producers, 2006

m tonnes



*Assuming merger goes ahead
†Includes the assets of SUAL and Glencore

Source: Brook Hunt

aluminium price to twice its level of 18 months ago, the price has hovered around $2,700 a tonne for some months.

Where it will go next is the subject of much debate. Until a few years ago China was a net importer of aluminium. Since then both production and consumption have exploded to satisfy the demands of the expanding economy. But production outpaced consumption, making China a net exporter. Jim Lennon, an analyst with Macquarie Bank, points out that aluminium plants can be built far more quickly there than anywhere else in the world, and at about a quarter of the cost.

China is home to Chalco, one of the giants of the aluminium business, and to over a third of the world's smelters. But although plants can be built

cheaply in China, production costs are
among the highest in the world. China relies on expensive imported alumina, the refined version of bauxite, the ore from which aluminium is made. And smelting it uses vast amounts of energy, accounting for one-third of the costs in an average plant. The government has tried to rein in aluminium producers on the ground that they are hogging prized energy resources that it would prefer to divert to other parts of the economy. Last year a tax rebate on the export of aluminium ingots was eliminated, and then an export tax was imposed.

But China's policymakers may fail to stem the power drain. Ingot exports have slowed down in recent months but exports of semi-finished and finished aluminium products, which are much harder to track, may have filled the gap. Demand for aluminium grew by 23% in China in 2006 and is expected to expand by 30% this year. The government may try to intervene to prevent production from expanding commensurately; but it may not succeed.

Even so, many industry watchers believe that China will once again become a net importer of aluminium. On current trends world demand for the metal will reach 70m tonnes by 2020. But where will the extra supply come from? There are few places with the abundant cheap energy needed to make the stuff. Alcan is probably best placed to take advantage of growing demand, because a deal with Quebec, its home province, provides it with cheap, plentiful hydro-electric power. Hence its appeal to Rio Tinto.

What of BHP Billiton's supposed interest in Alcoa? Unlike Alcan, the American firm does not have access to bargain-priced power supplies. And along with its smelters and bauxite deposits, it has a raft of less tasty downstream assets, such as a packaging business with pitiful margins. But BHP Billiton could team up with a private-equity buyer to offload the less desirable parts of Alcoa, and some analysts reckon that of all the potential suitors it is in the best position to extract savings from a deal. So it might still prove enticing, particularly if BHP Billiton shares Mr Albanese's cheerful forecast of growing demand for aluminium from another source. "Where goes China, India is likely to follow," he says.

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ISRI 2006 Annual Convention & Exposition:
Spotlight on Aluminium, 4 April 2006

Aluminium market outlook: Going from strength to strength

Robin Bhar, Base Metals Strategist

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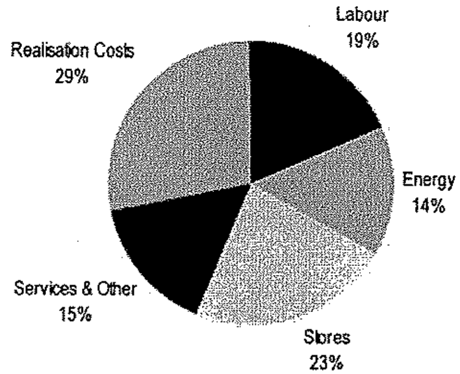
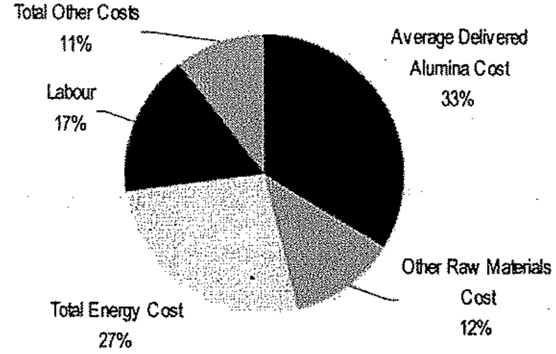
April 2006

Secular theme #1: Costs are rising rapidly

Global Copper Direct Cash Cost Breakdown, 2004

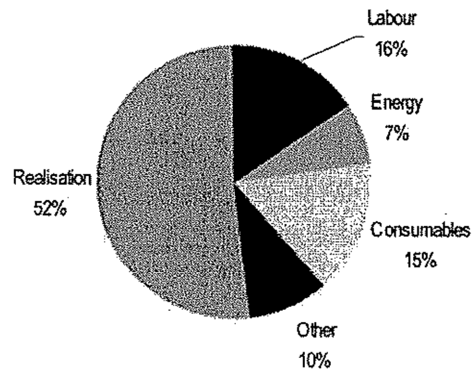


Global Aluminium Smelters Cost Breakdown, 2004



- Most extreme for aluminium: re-rating of energy values expected to impact aluminium prices – floor
- Labour, equipment, feedstock, royalty costs rising as well
- C$, A$, Real, Rand
- Operations, across sub-sectors experiencing costs increases between 20% to 50%

Global Zinc Cost Breakdown, 2004



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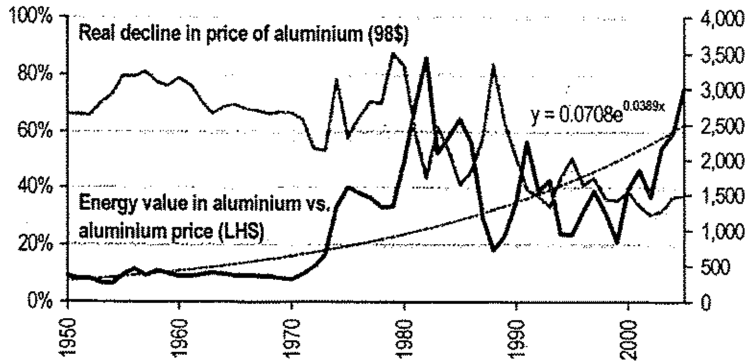
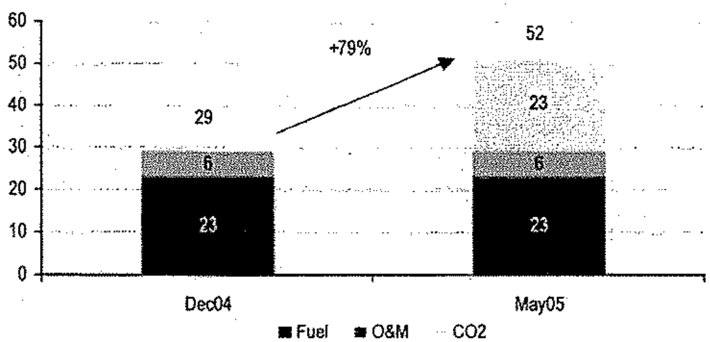
Source: Brook Hunt

Aluminium: 'power hungry', prices revised up on power costs

Energy driving aluminium prices



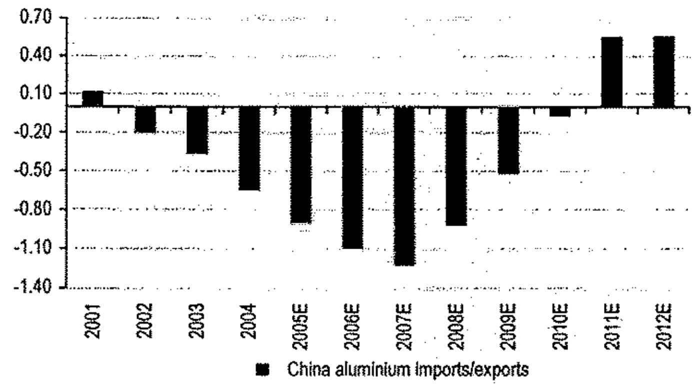
Impact of emissions trading on coal plant op cost €/MWh



Aluminium price revisions

		2006E	2007E
Aluminium			
-new	US¢/lb	110	95
-previous	US¢/lb	84	77
-change		*31%*	*23%*

China net import/exports from 2001 in mt



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Source: China Custom Statistics, Datastream, UBS estimates

Alumina: market details - forecasts

Global Alumina Market

		2002	2003	2004	2005	2006E	2007E	2008E	2009E	2010E
Demand	mt	50.8	54.7	58.5	62.4	64.4	67.8	70.6	73.9	76.0
demand growth	%	6.5	7.5	7.0	6.6	3.2	5.3	4.2	4.7	2.8
Capacity	mt	60.0	62.5	64.9	69.1	73.3	77.8	81.7	87.4	87.1
capacity growth	%	5.3	4.2	3.8	6.4	6.1	6.2	5.0	7.0	-0.4
utilisation rate	%	93	95	98	96	96	96	95	95	95
Production	mt	55.8	59.4	63.4	66.3	70.3	74.7	77.6	83.0	82.7
nonmetallugical production	mt	4.9	4.9	5.1	5.3	5.6	6.0	6.2	6.6	6.6
metallurgical grade production	mt	50.9	54.5	58.3	61.0	64.7	68.7	71.4	76.4	76.1
growth in MGA production	%	3.0	7.1	7.0	4.6	6.1	6.2	3.9	7.0	-0.4
Market Balance	mt	0.1	-0.2	-0.2	-1.4	0.3	1.0	0.8	2.5	0.1
opening stock	mt	9.4	9.5	9.3	9.1	7.7	8.0	9.0	9.8	12.3
closing stock	mt	9.5	9.3	9.1	7.7	8.0	9.0	9.8	12.3	12.4
Stock consumption ratio	wks	9.7	8.8	8.1	6.4	6.5	6.9	7.2	8.6	8.5
Spot price	US$/t	149	274	404	448	575	350	220	220	220
Spot price	% LME	11.0	19.2	23.5	23.6	23.7	16.7	12.5	13.9	13.9
Contract price	US$/t	165	177	212	259	412	314	247	222	222
Contract price	% LME	12.3	12.4	12.4	13.7	17.0	15.0	14.0	14.0	14.0

China's Alumina Market

		2002	2003	2004	2005	2006E	2007E	2008E	2009E	2010E
Industrial production growth										
China	%	18.2	25.5	16.4	13.4	11.8	11.5	11.5	11.5	11.5
Global	%	1.1	2.5	5.1	3.8	4.0	4.0	4.0	4.0	4.0
China's alumina market										
Demand	mt	10.0	11.7	12.9	15.2	17.0	18.6	19.9	20.4	20.4
Supply (domestic)	mt	5.4	6.2	7.1	8.0	9.8	11.2	12.4	13.6	13.6
Surplus (deficit)	mt	-4.6	-5.6	-5.9	-7.1	-7.1	-7.4	-7.5	-6.8	-6.8
Global alumina market ex-China										
Demand	mt	40.8	42.9	45.6	47.2	47.4	49.2	50.7	53.5	55.5
Supply	mt	45.5	48.3	51.2	53.0	54.9	57.5	59.0	62.7	62.5
Surplus (deficit)	mt	4.6	5.4	5.6	5.8	7.5	8.3	8.3	9.3	6.9
Global surplus inc China	mt	0.1	-0.2	-0.2	-1.4	0.3	1.0	0.8	2.5	0.1
Demand growth										
China	mt	3.1	1.7	1.2	2.3	1.8	1.6	1.3	0.5	0.0
Global ex-China	mt	0.0	2.1	2.7	1.6	0.2	1.8	1.5	2.8	2.1
China	%	45.6	17.2	10.0	17.7	11.7	9.4	7.2	2.6	0.0
Global ex-China	%	-0.1	5.2	6.2	3.4	0.5	3.8	3.0	5.5	3.9

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Source: LME, AME, Brook Hunt, CRU, UBS estimates

United States Committee on
Energy & Natural Resources

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Hearing Schedule

Printable Version

:alifornia's Electricity ~~Crisis~~ and Implications for the West
Vednesday, January 31, 2001

Irett Wilcox

3ood morning, Chairman Murkowski and Members of the Committee. My name is Brett Wilcox. I am he CEO of Golden Northwest Aluminum, the corporate parent of Goldendale Aluminum Company ınd Northwest Aluminum Company. We own and operate two primary aluminum smelters and ıssociated facilities in Goldendale, Washington, and The Dalles, Oregon. We are by far the largest :mployer in these beautiful but economically distressed rural areas. We employ a total of 1,225 ıighly paid workers, at full production.

Jnfortunately, we are no longer at full production. Our primary aluminum production is now almost completely curtailed. The reason is simple: power prices in the West are currently too high to support aluminum production. Other energy intensive manufacturing companies that are exposed to the market price for power also have had to curtail production. Soon, when high market prices for power purchases are passed through rates charged by the Bonneville Power Administration and local utilities, other Northwest manufacturing and industrial jobs, as well as agricultural jobs that depend on irrigation pumping , will be lost. Make no mistake about it: the crisis in the West is not just about electricity bills. It is also about paychecks.

So far, our company has been able to mitigate the impact of higher power costs because we purchased some of our power under long-term "take-or-pay" contracts with rights to remarket any power that we didn't use. Through agreements with BPA and our union, the United Steelworkers of America, we were able to reduce consumption, remarket the power made available, and use the net financial benefits in the Northwest to protect our workers, share with BPA, and help pay for new conventional and renewable power resources to supply a portion of our long-term power requirements. I've attached to my testimony our release explaining our curtailment and remarketing.

The electricity crisis in California has adversely affected the entire west coast. Some of the causes are obvious: physical shortages of generating capacity, below normal precipitation and hydro power, bottlenecks in power transmission and gas pipeline capacity, increases in the price of natural gas, and resource outages. But the most frustrating cause is that the "rules of the game" California adopted for electric power restructuring—unlike the rules in other states—have themselves driven up prices not only in California, but in the Northwest as well.

The sharp drop in demand that usually follows a sharp increase in the price of any commodity has not yet occurred in California, where most end-users have not yet received any "price signal" of the crisis. Instead of higher prices balancing the market, Californians have had to experience rolling blackouts. In the Northwest, however, the price impacts are now being felt by end-users. The full force was felt first by the aluminum smelters, then by the industrial customers of several large utilities. Now it is about to be felt by almost everyone in Washington, Oregon, Idaho, and western Montana.

This crisis has few short-term fixes to increase supply. We do need to speed up the permitting process required to develop new generating resources and to build new power transmission and gas pipelines. One short-term way to increase the supplies of power is to the temporary relaxation of some power plant emission controls, as Governor Locke of Washington has just announced. We also need to review and remove constraints on hydro operations—especially spilling water—that significantly reduce power generation without really helping endangered salmon.

Near-term responses need to focus on ways to reduce demand. Demand reductions – perhaps massive ones – will occur. The issue is how best to manage them, and how to ensure that they do not destroy the economic well being of the West. End-use consumers can't be spared the rate impacts of high power costs for long. But those high costs can be passed through in two ways: either by melding costs and raising the average rate of every kilowatt-hour, or by passing through actual high market prices just on the marginal kilowatt-hours of consumption.

If soaring wholesale power costs drive up the average cost of power, then residential customers will be hit hard not only in their utility bills, but even harder in their paychecks. This is because any significant increase in the average cost of power will shut down a huge portion of Northwest manufacturing, industry, and agriculture – and presumably the same is true in California. In a competitive global economy, even a small increase in the average cost of its entire power supply can make a company's entire production uneconomic.

The alternative is to make end-use consumers feel the impact of higher wholesale power costs at the margin. This gives real price signals. Increases in consumption require someone to buy very expensive power: the end-use consumer should feel that cost. Decreases in consumption reduce the need to buy very expensive power: the end-use consumer should experience that saving. Businesses can conserve energy at the margin, ensuring that the bulk of their production continues to be competitive. In agriculture, for example, a farmer can take some acreage out of production for a period, rather than not being able to farm at all because of a large increase in the cost of his entire irrigation load.

A very practical application of this is possible in the Northwest through the Bonneville Power Administration ("BPA"). BPA supplies forty-five percent (45%) of all power in the Northwest. Until recently, BPA planned to continue selling power to utilities at $20-$25 per megawatt-hour ("MWh"). Now BPA expects to pay $125/ MWh to buy the power it needs to meet its load growth. As a result, BPA last week announced a sixty percent (60%) rate increase for its customers for the entire next five years. This comes on top of very large rate increases many Northwest utilities have already imposed on their retail customers.

Dividing each customer's purchases into two parts could mitigate this situation. The larger and less expensive portion would be power that BPA can supply without buying expensive additional supplies in the market. The smaller and much more expensive portion would represent the portion that BPA must spend huge sums to buy. Each customer should be able to turn the latter portion back to BPA, allowing BPA either to remarket it at high market prices and credit the proceeds against that customer's power bill, or to reduce the amount that BPA itself must buy to meet its customer's loads. This not only helps the customer and the economy, but also ensures that BPA can meet its treasury payments no matter what happens to the wholesale cost of power.

I know this idea is practical and can work. I know because our company has already pioneered this with BPA. We curtailed our smelting load, returned the power to BPA for remarketing, and are putting the remarketing proceeds to beneficial use. Demand for power is temporarily reduced, BPA is on a sounder financial footing, our workers are still getting paid, and we are putting money aside to develop new power sources, including wind generators. What I'm proposing here is an adaptation of that already-successful effort, but one that could apply broadly to all BPA customers, reducing overall BPA requirements by perhaps ten to fifteen percent (10-15%). Only a broad effort can spare everyone deep pain.

I've attached to my testimony a paper showing how this concept can work to save aluminum jobs and other jobs throughout the Northwest until the day when power supplies increase and power prices become more reasonable. I hope you will review this paper and contact me with any questions. I hope you will urge BPA to implement this approach.

Finally, turning to the long-term, there are many potential solutions that have been covered by others here today. I would like to mention one additional solution that deserves more attention. The vast reserves of natural gas in Alaska, the Beaufort Sea, and northern Canada are a key to the long-term energy supply and continued economic prosperity of the United States and Canada alike. Left to their own devices, market forces will eventually be sufficient to get this gas to the Lower 48 – but the gas will arrive here more slowly, in smaller volumes, and at higher prices than would be optimal for the North American economy.

This is an instance where market forces could use some help in the form of active diplomacy and initiative by the U.S. and Canadian governments. The obstacles to an optimal timing, volume, and price of northern gas are primarily economic obstacles within Canada – particularly the perceived interests of those who benefit from today's high gas prices and today's constrained limits on available pipeline capacity. Those interests are legitimate, but they can be reconciled with the broader interests of the economic health of both nations. If this happens – and the two governments, working together, can bring it about - then the northern gas should be able to get here quickly, in large volumes, and at prices low enough to spur decades of continued economic prosperity.

Thank you for your time and consideration.

Energy and Natural Resources Committee
304 Dirksen Senate Building
Washington, DC 20510
(202) 224-4971

THE WALL STREET JOURNAL
The Wall Street Journal

July 6, 2007 Friday

SECTION: Corporate Focus; Pg. A10

LENGTH: 1073 words

HEADLINE: Metal Makers Go Far for Cheap Fuel --- Trinidad Draws Nucor, Others as Competition Spurs Cost-Saving Moves

BYLINE: By Paul Glader

BODY:

POINT LISAS, Trinidad -- Les Hart pointed along the coastline of this sunny Caribbean shore the way a tourist might point out a dolphin.

But he was indicating a series of fat pipelines bringing cheap, abundant natural gas from an undersea field to the iron refinery he manages. The fuel supply's economics are so compelling that Mr. Hart's employer, steelmaker Nucor Corp., cut the refinery into pieces and shipped it across the sea from its original home near New Orleans to take advantage of the lower costs.

"These are the two reasons people set up shop here," said Mr. Hart, the facility's general manager. "Natural gas and a port."

Metal makers such as Nucor are flocking to Trinidad, a tiny island nation seven miles off the coast of Venezuela that is trying to capitalize on its natural-gas and oil resources. While Venezuela nationalizes industries and kicks out large multinational investors, Trinidad officials say they talk with three or four companies a month that want to join players such as Nucor and steel giant Mittal Steel Co.

Western manufacturers, chemical makers and metal companies face intensifying competition from fast-growing companies in places like the Middle East and Russia that offer cheap sources of oil and gas. They also face growing competition from Asian companies with other **cost** advantages, like labor.

In response, they are flocking to countries such as Trinidad and Iceland, and to other places farther afield with cheap and abundant energy. Century **Aluminum** Co., of Monterey, Calif., is expanding its **aluminum smelter** in Grundartangi, Iceland. Alcoa Inc., based in both Pittsburgh and New York, would also like to expand in Iceland and build a second **aluminum smelter** there to take advantage of lower-**cost** energy generated by hydropower or geothermal power.

Rival aluminum maker Alcan Inc., of Montreal, has focused on gaining a presence in the energy-rich Middle East, recently pledging $7 billion toward a partnership with a government mining, refining and smelting operation in Saudi Arabia. The company already has a joint-venture smelter project under way in Sohar, Oman, that is slated to start producing next year.

Many of the markets bring their own sets of challenges. Environmental concerns and protests in Iceland could limit future development and add to costs. Alcan's joint-venture approach and minority stakes in the Middle East make it more difficult to control a project and therefore difficult to maximize revenue and profit there.

Meanwhile, companies locating in Trinidad face a labor shortage. And they must worry about the extent of the energy reserves. Some estimate the country has only 30 years of natural-gas reserves left. Ken Julien, chairman of Trinidad's Natural Gas Export Task Force, which makes decisions on how to use the country's reserves, says more untapped deposits could be discovered.

"The pattern in Trinidad is the more they use, the more they find," he said. Trinidad is the 23rd-largest producer of natural gas, according to Frontier Strategy Group of Cambridge, Mass.

Nucor's plant is one of the new, large-scale metal-making operations valued at more than $3 billion that are either already running or on the drawing board for the island. Indian steel maker Essar Group PLC and Alcoa have plans for manufacturing facilities that will cost more than $1 billion each.

Energy-intensive manufacturers also welcome Trinidad's relatively streamlined bureaucracy and stability. "Because we are a small country with a centralized decision-making process, companies get a quick decision," said Mr. Julien, a former engineering professor.

Nucor, of Charlotte, N.C., didn't have much in the way of overseas assets when it acquired the New Orleans refinery in 2004. Joe Rutkowski, an executive vice president at Nucor for business development, said the company couldn't find an efficient way to operate the Louisiana plant because of high natural-gas prices. It considered moving the refinery to the Middle East or Latin America, including Venezuela, but couldn't accept the risk.

"You can talk about Venezuela, but at the end of the day you are scared to death of political instability there," Mr. Rutkowski said.

The company settled on Point Lisas, cutting up and moving the plant on 13 barges -- the last of it five days before Hurricane Katrina struck New Orleans in 2005. Production at the reassembled plant began earlier this year and is expected to reach two million tons a year of special iron-ore pellets, which will be shipped to Nucor's electric-arc furnaces in Alabama and South Carolina to be melted into steel.

Trinidad boasted a 12.6% annual growth rate last year. That success has in turn created a skilled-labor shortage in a country whose unemployment has dropped to about 5% from 10.5% in 2003, according to government data.

"Wages tend to increase at a higher rate than they do in the States because there is competition for these good people," said Nucor's Mr. Hart, noting that wages are going up 8% a year. "We are trying to recalibrate ourselves to what we need to pay our folks competitively so we don't actually lose our folks to other companies."

It is hard, too, he said, finding highly skilled workers that fit in with Nucor's culture, known for being fast-paced, lean and bonus-oriented, with extra pay tied to high levels of production. The company puts potential recruits through psychological screening to see if they fit the mold.

Three years ago, the country launched the University of Trinidad and Tobago, with a heavy focus on manufacturing and engineering. The university is joining up with companies to have students work on projects for industry and to make sure they learn the skills industries require.

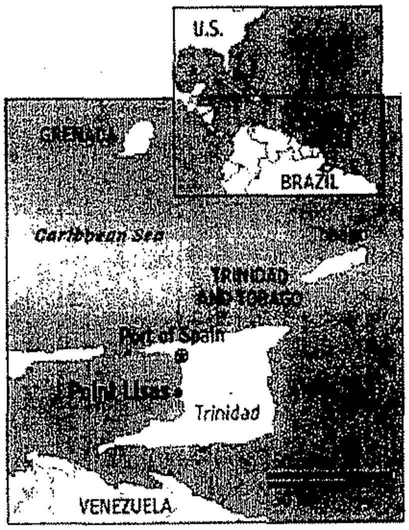
Mr. Hart said Nucor plans to team up more with the university and others to find workers such as Marcus Singh, a supervisor at the Nu-Iron plant.

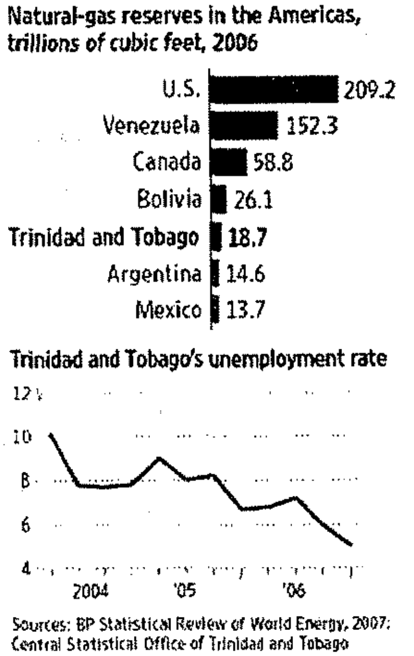
When he finishes his shift, Mr. Singh often heads to class to complete his chemical-engineering degree at the university's Point Lisas campus. After high school, Mr. Singh, now 35 years old, went to work for a string of industrial companies: an oil refinery, a methanol plant and a plant shipping liquefied natural gas.

But after a dozen years as an entry-level worker, factory jobs "got pretty boring," said Mr. Singh, who aspires to move further into management at Nucor. "I needed something a little more challenging."

Inviting Shore

Metals companies and others are attracted to Trinidad's big natural-gas reserves and stable government, but a tight employment market is a concern.





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THE WALL STREET JOURNAL.
The Wall Street Journal

January 10, 2007 Wednesday

SECTION: THE ECONOMY; Pg. A2

LENGTH: 739 words

HEADLINE: Alcoa Net Soars, Easing Some Commodities Gloom

BYLINE: By Paul Glader

BODY:

Alcoa Inc., the world's largest aluminum producer, kicked off the fourth-quarter earnings season with strong results, suggesting that the wave of rising commodity demand is far from over, even as some commodity prices appear to have reached price ceilings.

The Pittsburgh-based company, which has executive offices in New York, cited higher metal prices and strong demand for aluminum in products such as airplanes, heavy trucks and commercial construction for the profit gain.

The latest figures included $386 million in charges related to a restructuring, involving the spinoff of the soft-alloys business, plant closures and a 5% global work-force reduction, representing 6,700 jobs, all expected to occur in 2007.

Excluding restructuring and impairment charges, the company earned $644 million, or 74 cents a share. The earnings results without the restructuring charges beat Wall Street expectations. On average, analysts polled by Thomson Financial forecast earnings of 65 cents a share.

"As we enter 2007, market fundamentals remain strong," said Chairman and Chief Executive Alain Belda. He said the company is focusing on profitability, while reinvesting its cash building new plants and modernizing old ones to be poised for future growth.

After-tax operating income in the latest quarter improved in five of the six major business units with flat-rolled products remaining even with the year-earlier period. Although Alcoa has been cutting costs for years, management has been frustrated that its financial performance and cost-cutting moves have had little impact on the company's share price, which has fluctuated but not moved up as significantly as some rival aluminum producers or other metals and mining companies.

Alcoa shares traded at $29.87, up $1.35, or 4.7% after-hours, from their close of $28.52 at 4 p.m. on the New York Stock Exchange.

As Wall Street worries about the length and breadth of the global commodity boom and whether a downturn is weighing on metal-intensive American manufacturing, Alcoa's earnings indicate that global demand remains strong and a widespread commodity downturn isn't yet imminent.

In some cases, weakness in certain end markets is marked by pockets of strength that appear to be supporting demand and prices for now. For example, while the Big Three auto makers in the U.S. are curbing production, foreign auto makers with new plants in the U.S. are strong. And while the residential construction market is weaker, nonresidential construction has been solid.

Alcoa benefits, as well, by its global reach. While gross domestic product growth rates slowed down in the second half of 2006 in the U.S., it remained strong in developing regions and looks to be well above 3% in parts of Asia, Africa and Latin America in 2007 according to some economists. Alcoa's Mr.Belda predicts global aluminum demand will double in the next 15 years.

Still, some analysts see falling prices ahead. "My feeling is that eventually we are going to go back to much, much lower metal prices," said Chuck Bradford, a New York-based metals analyst with Bradford Research/Soleil. "These things are commodities. This is not a rocket science business." He predicts aluminum could eventually go back to $1 a pound in 2008 or 2009. At present, aluminum is just under $1.25 a pound on the London Metal Exchange, down from highs earlier in 2006.

As a result of the high price levels, those metals and mining companies with strong balance sheets are rushing to build plants or buy other companies in strategic, growth-oriented locations and markets while cutting **costs** to position themselves to increase revenue and profits in a more stable, less dramatic growth cycle. One big concern is whether China's market is becoming saturated and what impact that will have on demand.

Alcoa and other aluminum companies have run into obstacles expanding raw **aluminum** production, in large part because **aluminum smelting** is one of the most energy-intensive industries in the world and one that often draws protests from environmental interests. Alcoa, for example, has been planning to build a new smelter in Trinidad but must now find a new location for the plant after local protests hindered planning at an original site. The company does expect to finish constructing a new smelter in Iceland in the second quarter, its first new smelter in 20 years.

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COMMODITIES & AGRICULTURE: US smelters mull reopening: With Pacific north-west power prices back to normal, mothballed aluminium plants may become viable again, says Matthew Jones

By MATTHEW JONES, Financial Times
Published: Feb 06, 2002

Falling power prices in the north-western US are raising questions about when the region's aluminium smelters will be brought back onstream.

More than 1.6m tonnes of capacity was mothballed last year - about 8 per cent of the western world's total - due to a power crisis in the Pacific north-west.

Now that power prices are back to normal, some observers believe smelters could be reopened by the second half of the year. This would be welcomed by laid-off workers but could keep aluminium prices depressed for the rest of the industry.

Production cuts by companies such as Alcoa, Kaiser Aluminum and Columbia Falls Aluminum helped balance the market at a time when industrial demand for aluminium was weak. The worry is that any reinstated capacity would disrupt this balance because sharp falls in automotive and aerospace output will keep demand relatively low this year.

This concern is already starting to filter through to the market, where aluminium prices on the London Metal Exchange have slipped from about Dollars 1,400 a tonne earlier this month to about Dollars 1,385 - some 7 per cent below the 10-year average.

"Half a million tonnes a year of excess production capacity is enough to have a significant effect on the price," says Adam Rowley of Macquarie Bank.

Spot power prices on the California-Oregon border surged to nearly Dollars 400 a megawatt-hour last January due to low reservoir levels for hydro-electric power plants and increasing demand from California's electricity-hungry information technology sector.

Smelters agreed to close their plants for two years after the Bonneville Power Administration, the federal agency responsible for providing low-cost power in the region, said prices would have to treble or quadruple.

Since then, high rainfall and new power plant building programmes have reduced spot power prices to about Dollars 16-Dollars 17 per MWh. With rivers and streams brimming full and snowfall slightly above average levels, forward power prices for the next 18 months are about Dollars 26 per MWh. This would allow smelters in the region to break even at an aluminium price of Dollars 1,250 a tonne.

There is already a precedent for smelting capacity to be brought back online. In Brazil, which suffered similar power shortages last year, some 200,000 tonnes a year of capacity is being restored progressively as power rationing is lifted.

Macquarie believes that at least a further 200,000 tonnes a year of Pacific Northwest capacity could be brought online by the year-end.

Two smelters with 380,000 tonnes a year of capacity have take-or-pay power contracts with BPA due to start in April, though BPA says it has had no indication to date that they are planning to restart production.

The remaining eight smelters, which have no such constraints, may prefer to buy cheaper power from the spot market while continuing to receive payments of Dollars 20 per MWh that BPA was forced to agree to cover labour costs.

"We're continuing to look at all the options and our decision will depend on market conditions," says Alcoa, the world's largest aluminium producer.

Companies thinking of restarting production will have an eye on their Chinese competitors.

Chinese production is expected to grow by about 18 per cent this year to 4m tonnes, according to figures released by Beijing Antaike Information, a state-owned metals analyst.

China's aluminium consumption has grown at an average of 13.5 per cent a year over the last 10 years but slowed to 8 per cent last year. Industry observers believe the country will become a net exporter this year, increasing pressure on western companies to keep their smelters closed.

Not everyone in the industry is bearish, however. Nick Moore, metals analyst at JP Morgan, believes demand for aluminium in China will be buoyed by projects in preparation for the 2008 Olympic games. Mr Moore says it is too early to say whether demand in the western world will recover, but that this possibility cannot yet be dismissed.

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:alifornia's Electricity Crisis and Implications for the West
Vednesday, January 31, 2001

Irett Wilcox

Good morning, Chairman Murkowski and Members of the Committee. My name is Brett Wilcox. I am he CEO of Golden Northwest Aluminum, the corporate parent of Goldendale Aluminum Company ind Northwest Aluminum Company. We own and operate two primary aluminum smelters and issociated facilities in Goldendale, Washington, and The Dalles, Oregon. We are by far the largest :mployer in these beautiful but economically distressed rural areas. We employ a total of 1,225 iighly paid workers, at full production.

Jnfortunately, we are no longer at full production. Our primary aluminum production is now almost completely curtailed. The reason is simple: power prices in the West are currently too high to support aluminum production. Other energy intensive manufacturing companies that are exposed to the market price for power also have had to curtail production. Soon, when high market prices for power purchases are passed through rates charged by the Bonneville Power Administration and local utilities, other Northwest manufacturing and industrial jobs, as well as agricultural jobs that depend on irrigation pumping , will be lost. Make no mistake about it: the crisis in the West is not just about electricity bills. It is also about paychecks.

So far, our company has been able to mitigate the impact of higher power costs because we purchased some of our power under long-term "take-or-pay" contracts with rights to remarket any power that we didn't use. Through agreements with BPA and our union, the United Steelworkers of America, we were able to reduce consumption, remarket the power made available, and use the net financial benefits in the Northwest to protect our workers, share with BPA, and help pay for new conventional and renewable power resources to supply a portion of our long-term power requirements. I've attached to my testimony our release explaining our curtailment and remarketing.

The electricity crisis in California has adversely affected the entire west coast. Some of the causes are obvious: physical shortages of generating capacity, below normal precipitation and hydro power, bottlenecks in power transmission and gas pipeline capacity, increases in the price of natural gas, and resource outages. But the most frustrating cause is that the "rules of the game" California adopted for electric power restructuring—unlike the rules in other states—have themselves driven up prices not only in California, but in the Northwest as well.

The sharp drop in demand that usually follows a sharp increase in the price of any commodity has not yet occurred in California, where most end-users have not yet received any "price signal" of the crisis. Instead of higher prices balancing the market, Californians have had to experience rolling blackouts. In the Northwest, however, the price impacts are now being felt by end-users. The full force was felt first by the aluminum smelters, then by the industrial customers of several large utilities. Now it is about to be felt by almost everyone in Washington, Oregon, Idaho, and western Montana.

This crisis has few short-term fixes to increase supply. We do need to speed up the permitting process required to develop new generating resources and to build new power transmission and gas pipelines. One short-term way to increase the supplies of power is to the temporary relaxation of some power plant emission controls, as Governor Locke of Washington has just announced. We also need to review and remove constraints on hydro operations—especially spilling water—that significantly reduce power generation without really helping endangered salmon.

Near-term responses need to focus on ways to reduce demand. Demand reductions - perhaps massive ones - will occur. The issue is how best to manage them, and how to ensure that they do not destroy the economic well being of the West. End-use consumers can't be spared the rate impacts of high power costs for long. But those high costs can be passed through in two ways: either by melding costs and raising the average rate of every kilowatt-hour, or by passing through actual high market prices just on the marginal kilowatt-hours of consumption.

If soaring wholesale power costs drive up the average cost of power, then residential customers will be hit hard not only in their utility bills, but even harder in their paychecks. This is because any significant increase in the average cost of power will shut down a huge portion of Northwest manufacturing, industry, and agriculture - and presumably the same is true in California. In a competitive global economy, even a small increase in the average cost of its entire power supply can make a company's entire production uneconomic.

The alternative is to make end-use consumers feel the impact of higher wholesale power costs at the margin. This gives real price signals. Increases in consumption require someone to buy very expensive power: the end-use consumer should feel that cost. Decreases in consumption reduce the need to buy very expensive power: the end-use consumer should experience that saving. Businesses can conserve energy at the margin, ensuring that the bulk of their production continues to be competitive. In agriculture, for example, a farmer can take some acreage out of production for a period, rather than not being able to farm at all because of a large increase in the cost of his entire irrigation load.

A very practical application of this is possible in the Northwest through the Bonneville Power Administration ("BPA"). BPA supplies forty-five percent (45%) of all power in the Northwest. Until recently, BPA planned to continue selling power to utilities at $20-$25 per megawatt-hour ("MWh"). Now BPA expects to pay $125/ MWh to buy the power it needs to meet its load growth. As a result, BPA last week announced a sixty percent (60%) rate increase for its customers for the entire next five years. This comes on top of very large rate increases many Northwest utilities have already imposed on their retail customers.

Dividing each customer's purchases into two parts could mitigate this situation. The larger and less expensive portion would be power that BPA can supply without buying expensive additional supplies in the market. The smaller and much more expensive portion would represent the portion that BPA must spend huge sums to buy. Each customer should be able to turn the latter portion back to BPA, allowing BPA either to remarket it at high market prices and credit the proceeds against that customer's power bill, or to reduce the amount that BPA itself must buy to meet its customer's loads. This not only helps the customer and the economy, but also ensures that BPA can meet its treasury payments no matter what happens to the wholesale cost of power.

I know this idea is practical and can work. I know because our company has already pioneered this with BPA. We curtailed our smelting load, returned the power to BPA for remarketing, and are putting the remarketing proceeds to beneficial use. Demand for power is temporarily reduced, BPA is on a sounder financial footing, our workers are still getting paid, and we are putting money aside to develop new power sources, including wind generators. What I'm proposing here is an adaptation of that already-successful effort, but one that could apply broadly to all BPA customers, reducing overall BPA requirements by perhaps ten to fifteen percent (10-15%). Only a broad effort can spare everyone deep pain.

I've attached to my testimony a paper showing how this concept can work to save aluminum jobs and other jobs throughout the Northwest until the day when power supplies increase and power prices become more reasonable. I hope you will review this paper and contact me with any questions. I hope you will urge BPA to implement this approach.

Finally, turning to the long-term, there are many potential solutions that have been covered by others here today. I would like to mention one additional solution that deserves more attention. The vast reserves of natural gas in Alaska, the Beaufort Sea, and northern Canada are a key to the long-term energy supply and continued economic prosperity of the United States and Canada alike. Left to their own devices, market forces will eventually be sufficient to get this gas to the Lower 48 - but the gas will arrive here more slowly, in smaller volumes, and at higher prices than would be optimal for the North American economy.

This is an instance where market forces could use some help in the form of active diplomacy and initiative by the U.S. and Canadian governments. The obstacles to an optimal timing, volume, and price of northern gas are primarily economic obstacles within Canada - particularly the perceived interests of those who benefit from today's high gas prices and today's constrained limits on available pipeline capacity. Those interests are legitimate, but they can be reconciled with the broader interests of the economic health of both nations. If this happens - and the two governments, working together, can bring it about – then the northern gas should be able to get here quickly, in large volumes, and at prices low enough to spur decades of continued economic prosperity.

Thank you for your time and consideration.

Energy and Natural Resources Committee
304 Dirksen Senate Building
Washington, DC 20510
(202) 224-4971

Vanalco shuts production at aluminum smelter-traders

NEW YORK, Sept 21 (Reuters) - U.S. aluminum market sources said Thursday that primary producer Vanalco Inc. closed the last of five potlines at its 115,000 tonne-per-year smelter in Vancouver, Wash., while it negotiates cheaper electricity rates, but the company would not confirm or deny the reports.

``We understand that they are shutting it down and selling their energy," said one East Coast metals broker, who added that traders who deal with Vanalco had confirmed widespread talk of the latest shutdown.

Vanalco, which did not return calls for comment on the latest closure, shut the first four production lines in early June, laying off roughly 450 employees, when power costs began to spike higher due to hot weather in the western United States.

Vanalco had a contracted power agreement with the Bonneville Power Administration for about five percent of its load, according to a Bonneville spokesman. The rest of its power was thought to be supplied at spot electricity prices from the open market.

Prices for power in the Pacific Northwest this week were as high as $210 per megawatt hour from about $30 per megawatt hour in May.

Historically, contract prices equalled $23 per megawatt hour, compared to a world average for the aluminum industry of about $18.50 per megawatt hour.

``We have seen a lot of those smelter shutdowns in the Northwest U.S. due to energy costs and electricity in particular," said William O'Neill, head of futures research at Merrill Lynch.

``That is the flip side of the (supply/demand) coin as compared to the potential for lower consumption on a global basis because of higher energy prices," he added.

Over the summer months, other U.S. producers including Kaiser Aluminum Corp. , Alcoa , and Ormet Corp. announced plans for curtailed output at operations in Washington, Oregon, Ohio and West Virginia for the same reason.

Initally, Vanalco said in June it would explore other sources of power with Bonneville and other Northwest electricity producers and power marketers.

This week on the London Metal Exchange, the aluminum market came under pressure as talk circulated that production may resume when Vanalco obtained a new power contract.

``The reason aluminum came off was because (Vanalco) was trying to negotiate a new energy package so that they could turn those potlines back on," said one broker from a New York trade house.

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Aluminum's Power Shift

Access to Cheap Electricity, Plentiful Natural Resources Fuels Rise of New Producers

By Paul Glader

A NEW BREED of aluminum makers, based in emerging economies and benefiting mainly from access to inexpensive electricity, are gearing up to challenge the supremacy of the industry's traditional giants, **Alcoa** Inc. and **Alcan** Inc.

The latest move came late last month, when **Rusal** Ltd. began finalizing a three-way agreement to take over **Sual Group**, a fellow Russian aluminum company, as well as the assets of Swiss commodities trader **Glencore International** AG. The new company would have the capacity to churn out five million metric tons of aluminum a year, outstripping the current No. 1 producer, Pittsburgh-based Alcoa, which has capacity for four million metric tons.

INDUSTRY FOCUS

A combined company would have an advantage because Russia has abundant supplies of natural gas, oil and hydro-electric power. Aluminum is the second-most power-intensive industry in the world, behind pulp making and paper-making, according to CRU International in London, and access to cheap power is fueling the rise of new producers. Other new producers are arising in India, Africa and the Middle East, where they also often benefit from either plentiful natural resources or abundant power.

Fueling the industry's growth is an explosion in demand for the lightweight metal, which is increasingly used in goods from automobile-engine blocks to beer cans. Alcoa predicts global consumption of aluminum will nearly double by 2020 to 60.6 million metric tons, from 31.6 million metric tons in 2005. It predicts Asia will consume about half of the world's aluminum by that time, with other emerging regions such as India, Brazil and Russia also experiencing a surge in demand. That means as many as 80 new aluminum smelters are needed by 2020, the company says.

Power Savers

Aluminum producers are shifting production to nations with low electricity costs. Average smelter power costs in 2005:

CIS*	$11.8 a megawatt-hour
Africa	16.2
Canada	16.7
Middle East	19.7
Oceania	22.5
Northern Europe	25.1
Latin America	26
World average	**26.9**
Southern Europe	27.9
U.S.	28.8
Asia	29.5
Eastern Europe	33.8
China	40.9
Central Europe	43.7

*Commonwealth of Independent States

Source: Alcoa

▲ *Alcoa last year signed an agreement with the government of Guinea to develop an alumina refinery there.*

Sohar Aluminum Co. is building a large smelter in Oman that will open in 2008, while **Aluminium Bahrain B.S.C (Alba)** has built the Alba smelter, one of the lowest-cost smelters in the world and the third-largest anywhere, with 3,000 employees and capacity to make 840,000 tons of aluminum a year. Bahrain has plans to expand it to make as much as 1.3 million metric tons a year.

Many of the new plants in the Middle East are partially owned by local governments, which are eager to diversify their economies and create jobs for their fast-growing, youthful populations. While the Middle East has relatively cheap power, it doesn't have the abundant raw materials that Africa, India, North America, Australia and South America have. And, China, while it consumes 30% of the world's aluminum, has cheap labor costs but not abundant raw materials or cheap energy. So Chinese companies are seeking partnerships with raw-materials producers in Australia and elsewhere.

It is the new wave of activity in Russia's aluminum industry that appears most likely to shift the balance of power in the global aluminum business. "Because of our natural [energy] advantages, we believe we have the ability to grow," says Peter Finnimore, director of sales and marketing for Rusal. "We think we will be the largest."

Rusal has several new smelters planned as well as upgrades of existing smelters. Indeed, the company already planned to hit five million tons of aluminum capacity on its own by 2013, even before it entered into talks with Sual and Glencore. It is also looking for acquisitions and joint ventures.

Some executives at Alcoa and Alcan dismiss Rusal as having old, less-efficient smelter technology.

For their part, Alcoa and Canada's Alcan, the world's No. 2 producer, have idled some smelters in North America and Europe, where energy tends to be more expensive, and are building ones in places such as Iceland, Trinidad and the Middle East.

Alcoa spokesman Kevin Lowery points out that the company owns power plants for some aluminum smelters in North America, providing it with more-reasonable energy prices, and says the company, in addition to currently planned new smelters, is considering smelters in locations as varied as Brunei, Siberia and Pakistan. "There is not a corner of the world we are not looking into right now," Mr. Lowery says.

Alcan's president and chief executive, Dick Evans, says the company is selling technology to several of the up-and-coming smelters in the Middle East and notes that the company has a 20% investment stake in the one in Oman. While many newcomers are building low-cost, efficient plants, he doesn't believe those companies will be major industry players for some time.

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 18) Provide all reports or presentations prepared by investment banking advisors (e.g., Goldman Sachs) for Big Rivers pertaining to the Unwind Transaction/Lease Agreement termination, or emergence from bankruptcy reorganization generally.

Response) Big Rivers objects to providing materials related to its emergence from bankruptcy on the grounds that such material is not relevant to the current proceeding, and that such request is overly broad and unduly burdensome. Big Rivers' bankruptcy plan of reorganization was consummated almost 10 years ago. The only roll Goldman Sachs had in the reorganization was in connection with remarketing Big Rivers' pollution control debt, which will not be affected by the Unwind. Without waiving that objection, attached are reports and presentations prepared by investment banking advisors for Big Rivers pertaining to the Unwind Transaction.

Witness) Mark W. Glotfelty

Goldman Sachs

Market Update and Structuring Discussion

Big Rivers Electric Corporation

A Touchstone Energy® Partner

April 25, 2007

Goldman Sachs

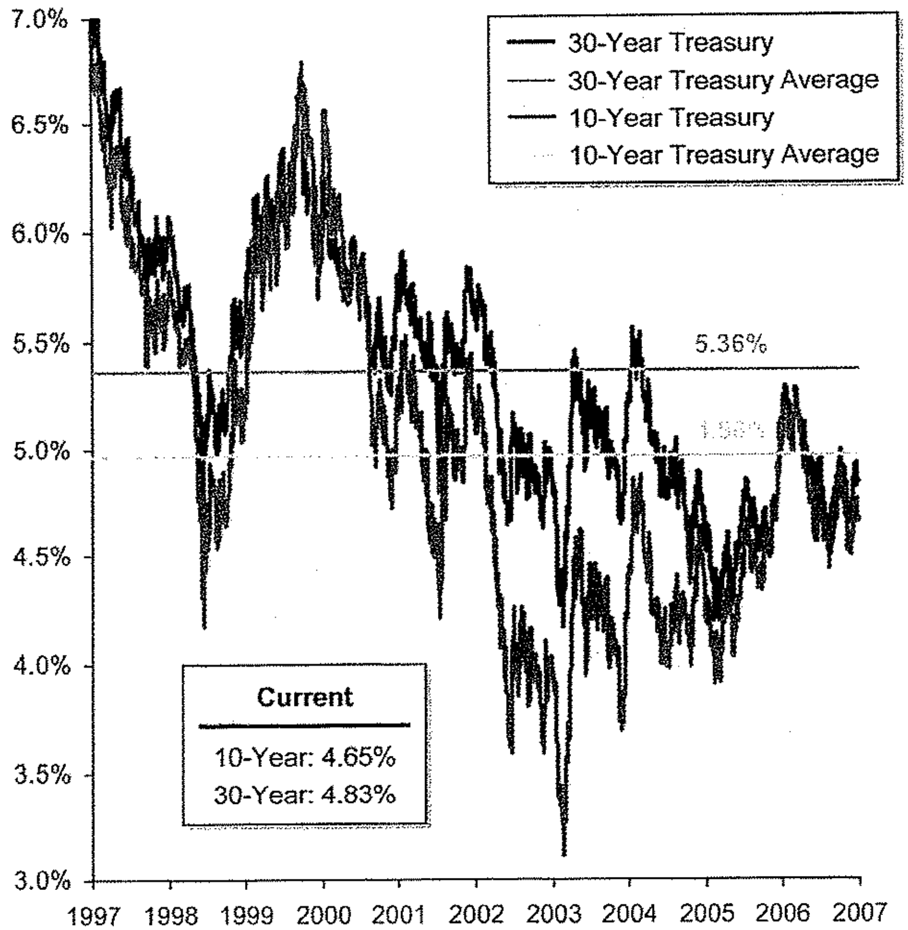
Summary of Prevailing Market Conditions

- Relatively low rates by historic standards
- Continued yield curve flatness
- Advantageous to issue long-dated fixed rate bonds
- Less immediate benefit from variable rate debt

Goldman Sachs

Taxable long-term rates are historically low, and the yield curve is historically flat.

Historical Treasury Rates[a]



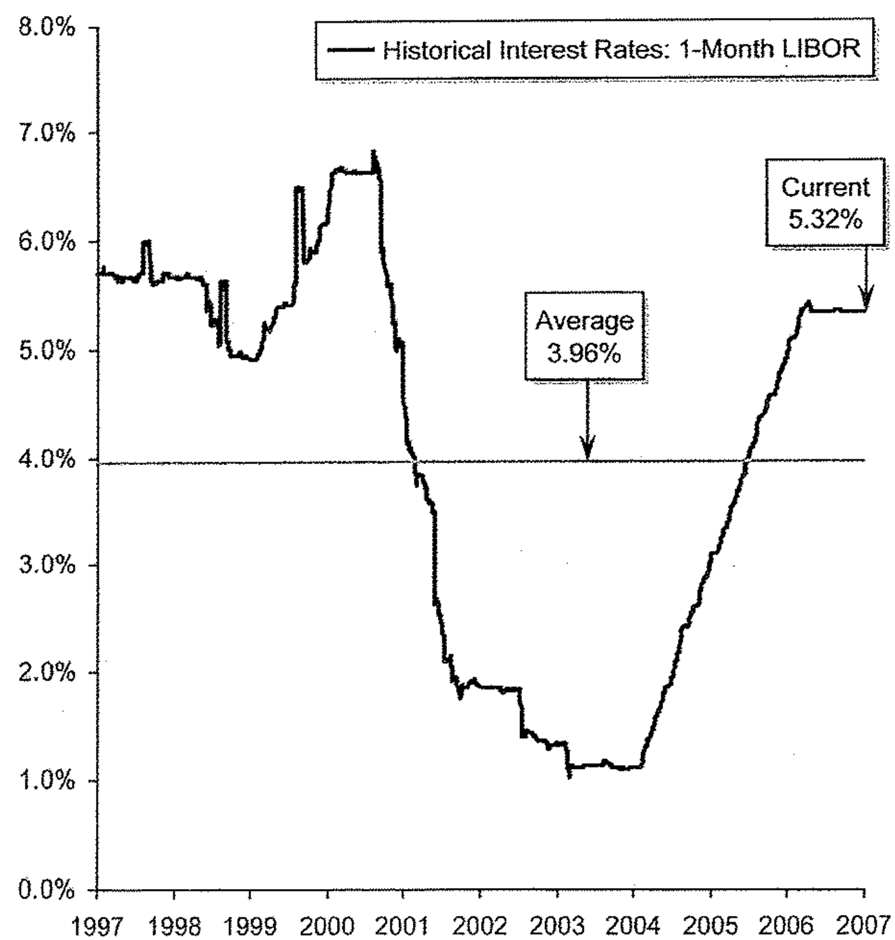
(a) Rates as of 4/23/2007.

30-Year Less 10-year UST

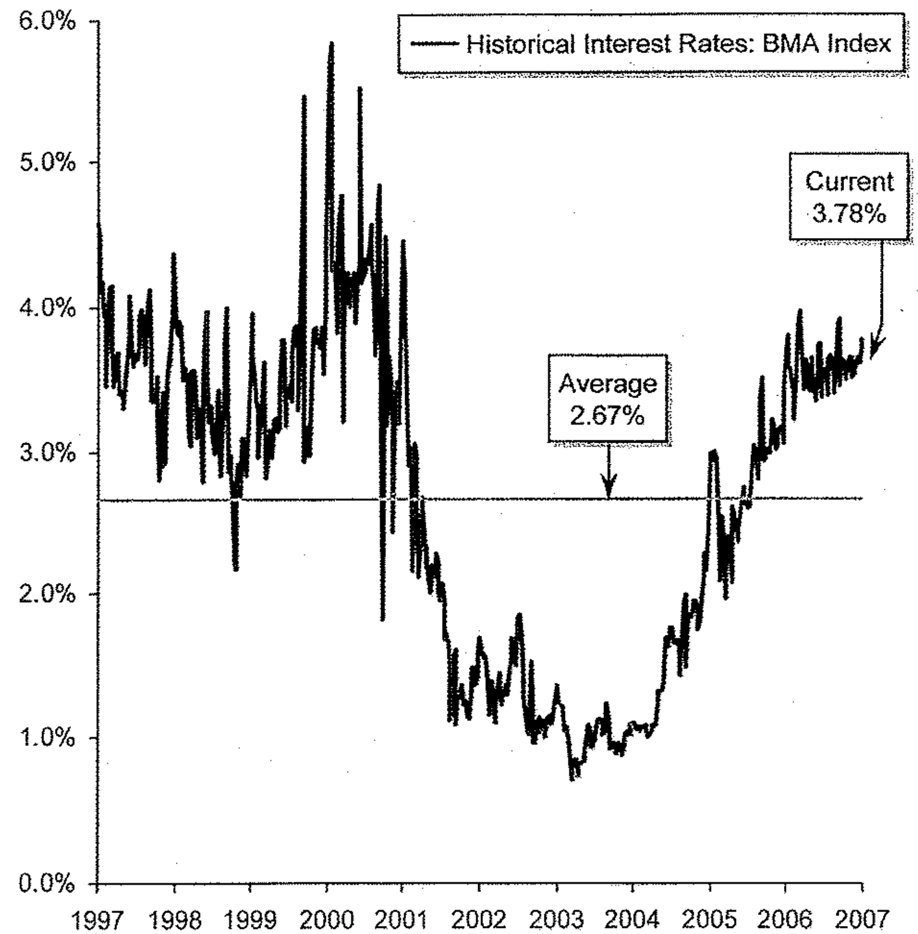
Goldman Sachs

Short-term interest rates have been steadily increasing.

1-Month LIBOR[a]



BMA Index[a]



(a) Rates as of 4/23/2007.

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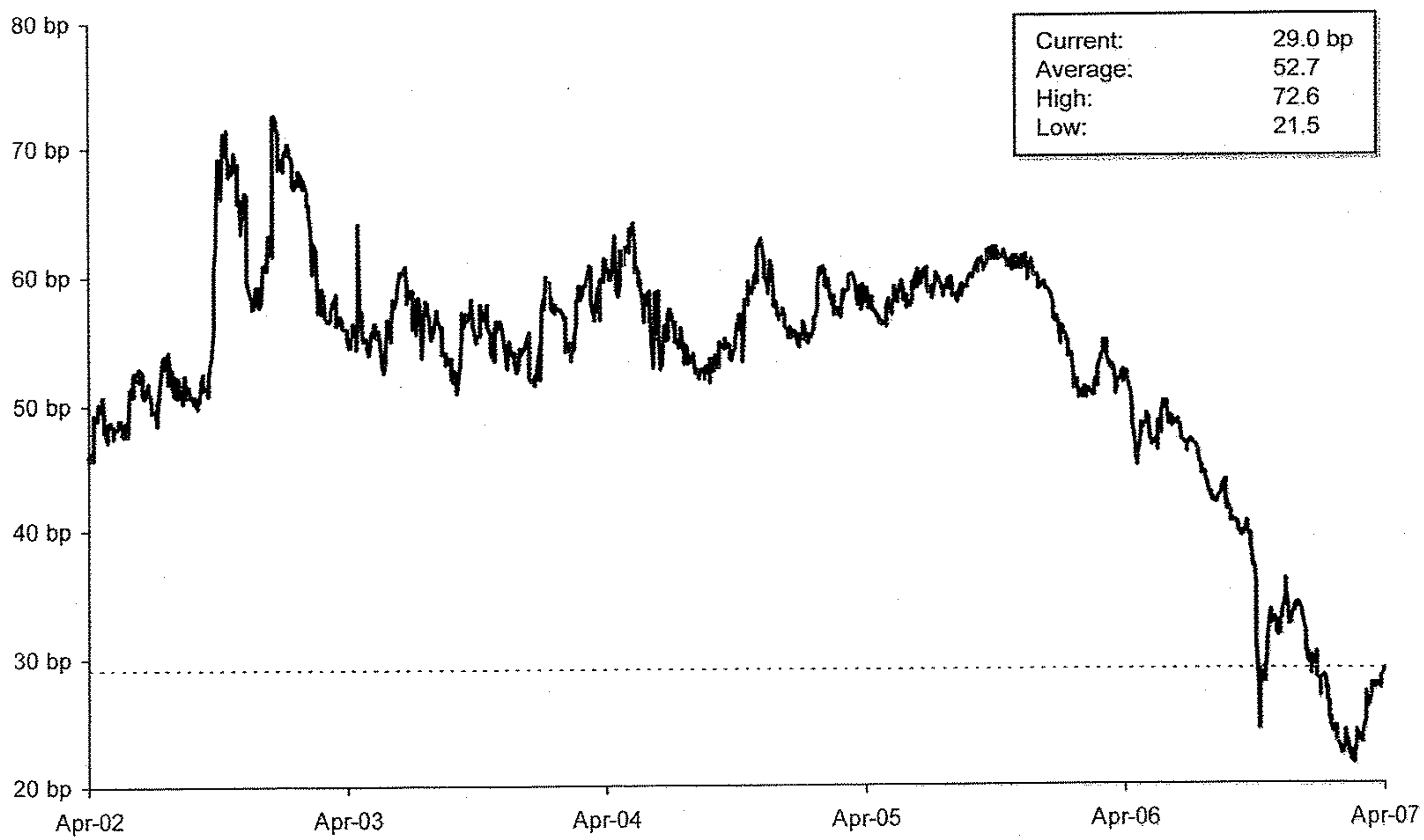
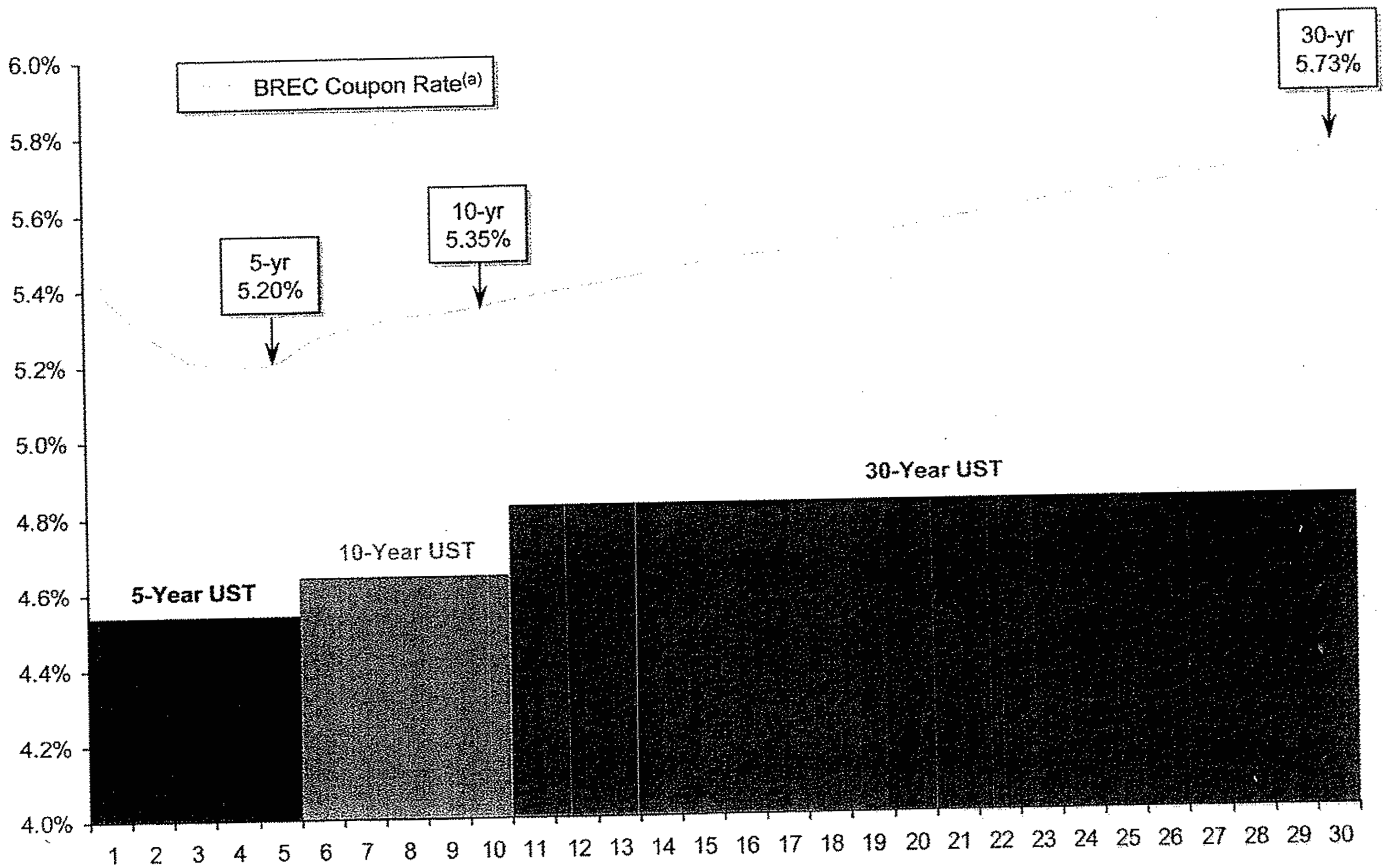
Value of tax risk has decreased drastically over the past two years.

30-year BMA minus 30-year 68% of LIBOR

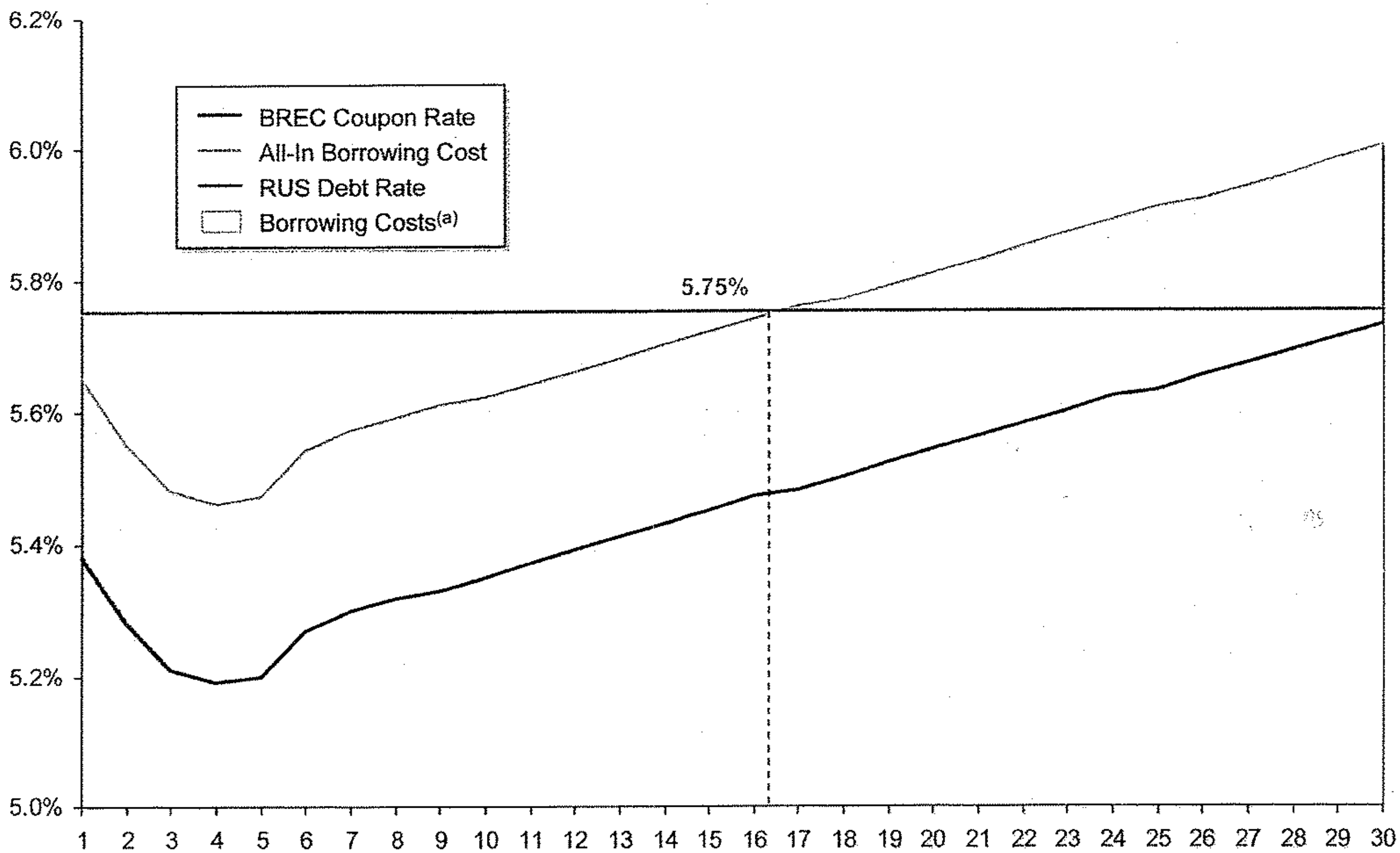


Indicative Big Rivers borrowing rates with underlying benchmark US Treasury rates.



(a) Fixed rate bonds assume between 65-90 bp credit spread across the yield curve (insured).
(b) As of 4/23/2007.

Big Rivers can borrow below the 5.75% debt rate through year 16.

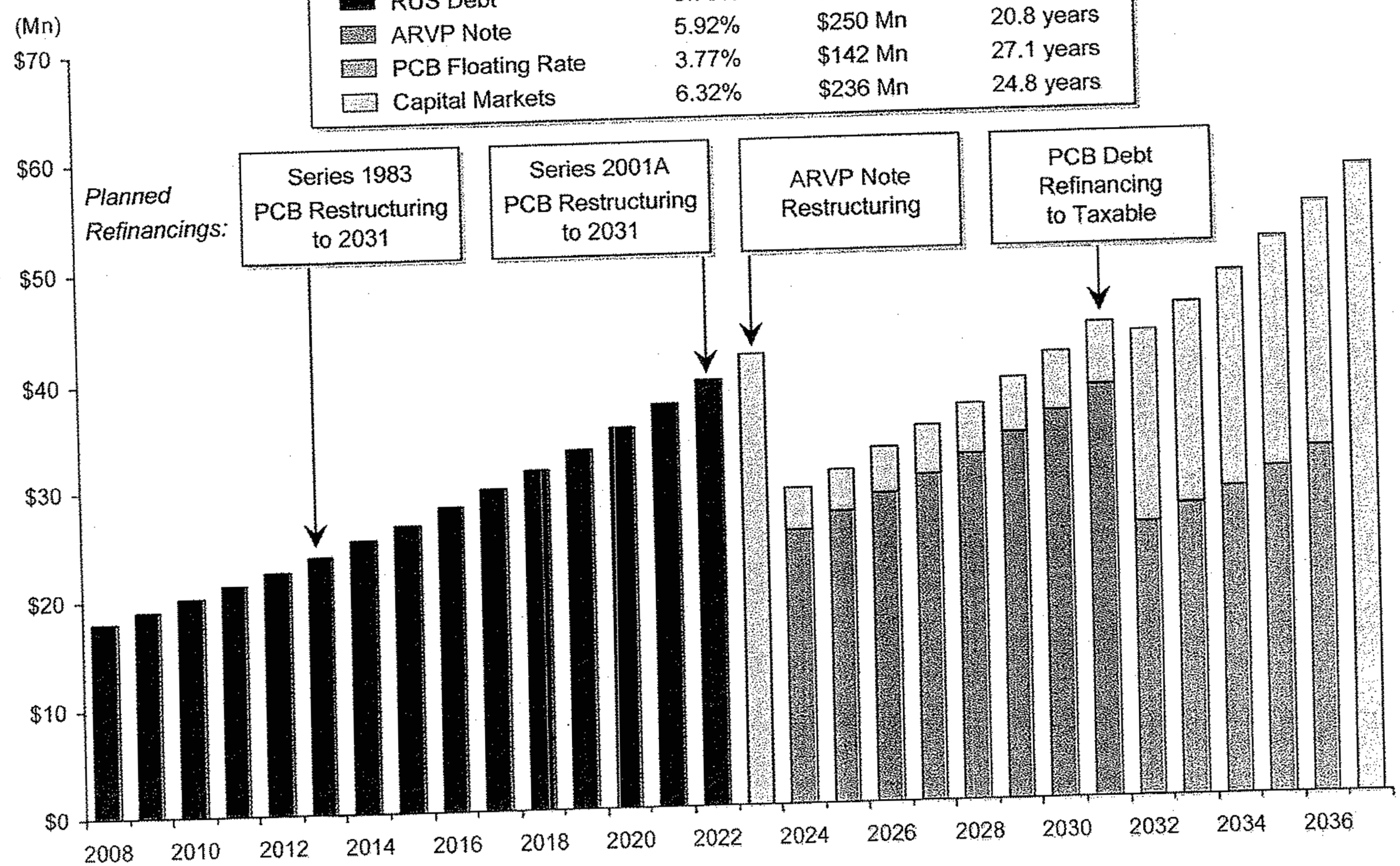


1% issuance costs vs. 1.75%

(a) Includes all costs of Issuance and assumed insurance premium.

Current Proposed Unwind Scenario Amortization[a]

	Yield	Par	Average Life
RUS Debt	5.75%	$410 Mn	9.0 years
ARVP Note	5.92%	$250 Mn	20.8 years
PCB Floating Rate	3.77%	$142 Mn	27.1 years
Capital Markets	6.32%	$236 Mn	24.8 years



(a) All information based on Unwind Model as of 4/12/07.

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Pricing Indications Based on Unwind Scenario Amortization

Maturity	Principal	Pricing[a]	Total Par	Avg. Life
01/01/23	$41,540,000			
01/01/24	3,780,000			
01/01/25	4,005,000			
01/01/26	4,245,000			
01/01/27	4,500,000			
01/01/28	4,770,000			
01/01/29	5,055,000	30yr UST+ 84-87	$235,545,000	24.3 yrs
01/01/30	5,355,000	5.69-5.72%		
01/01/31	5,680,000			
01/01/32	17,615,000			
01/01/33	18,675,000			
01/01/34	19,795,000			
01/01/35	20,980,000			
01/01/36	22,240,000			
01/01/37	57,310,000			
	$235,545,000		**$235,545,000**	

(a) Based on rates as of 4/19/07, 30-year UST @ 4.85%.

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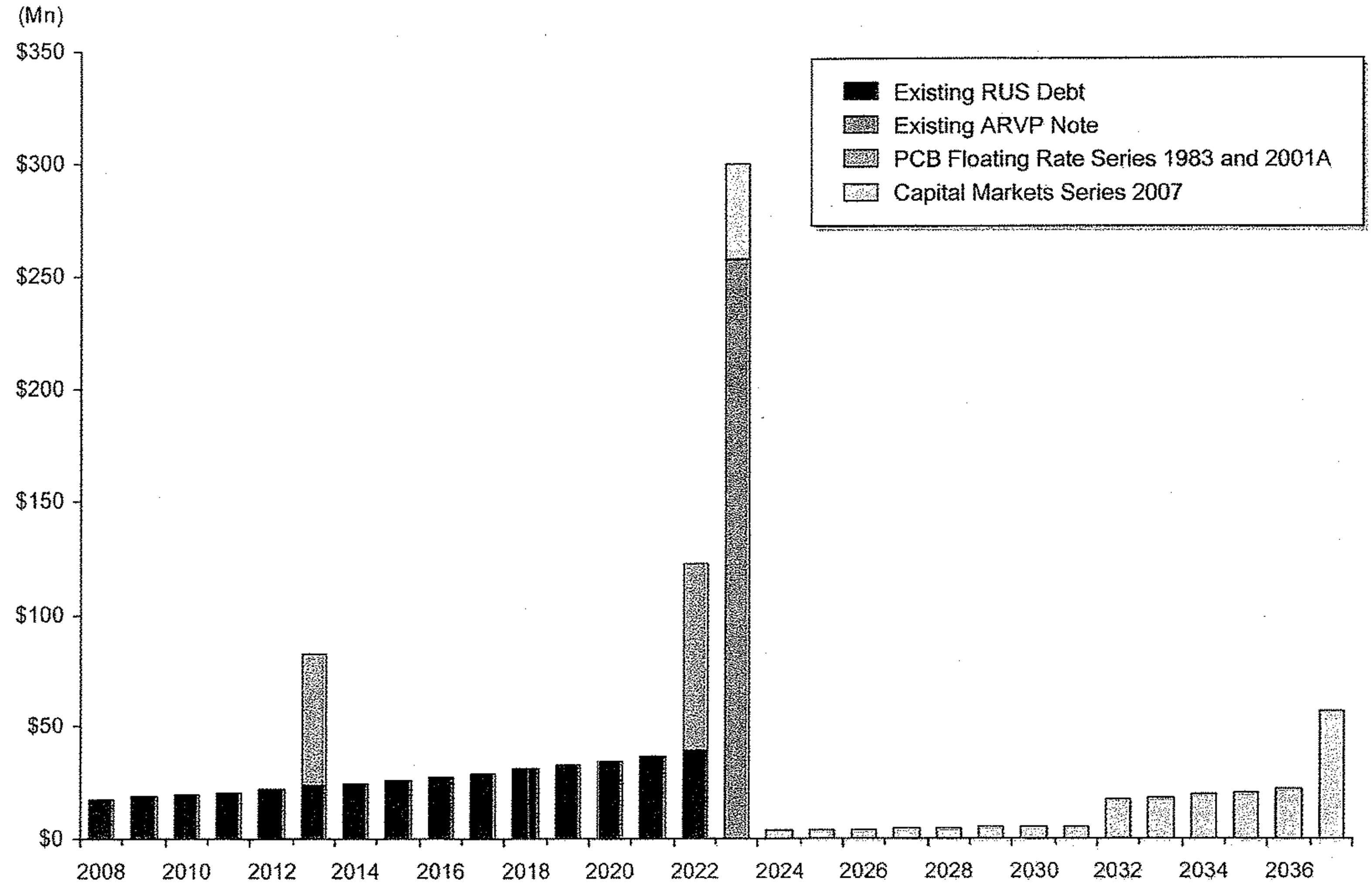
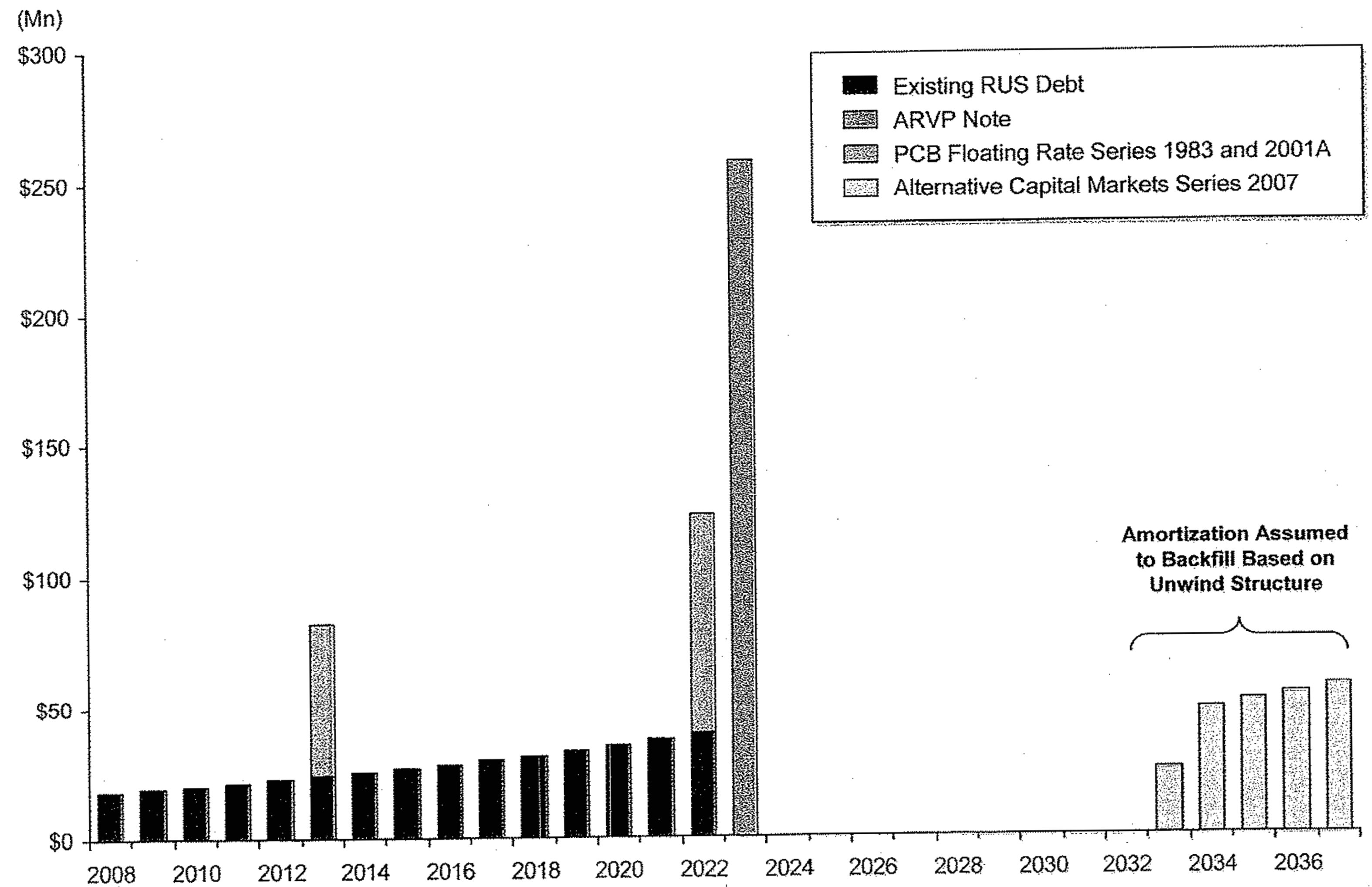
Unwind Scenario Amortization Schedule – Post Restructuring (does not account for future restructurings).



(a) All information based on Unwind Model as of 4/12/07.

Alternate Capital Markets Principal Amortization Schedule



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Goldman Sachs will reduce BREC's borrowing rate by comparing the pricing of two structuring alternatives.

Maturity	Principal	Pricing[a]	Total Par	Avg. Life
01/01/23				
01/01/24				
01/01/25				
01/01/26				
01/01/27				
01/01/28				
01/01/29				
01/01/30				
01/01/31				
01/01/32				
01/01/33	$25,045,743			
01/01/34	48,117,741			
01/01/35	51,005,002	30yr UST+ 85-90bp	$235,545,000	28.5 yrs.
01/01/36	54,065,407	5.70-5.75%		
01/01/37	57,311,107			
	$235,545,000		**$235,545,000**	

(a) Based on rates as of 4/19/07, 30-year UST @ 4.85%.

Goldman Sachs

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Item 19) Provide all documents which show financial comparisons (comparisons of financial metrics, e.g., Debt/EBITDA, TIER, DSC, etc.) of Big Rivers to "comparable companies" performed by or for Big Rivers.

Response) Please refer to the responses given for Item 20 and Item 29 of this Data Request.

Witness) C. William Blackburn

Item 20) Identify companies which Big Rivers views as being "comparable" to Big Rivers in terms of business purpose, and operating and financial metrics.

Response) Big Rivers is a generation and transmission (G&T) cooperative owned by the three member distribution cooperatives it serves. Big Rivers provides reliable wholesale electric service on a not-for-profit basis to its three member cooperatives. In turn, these cooperatives, owned by their more than 110,000 consumer-members, distribute the electricity at retail, on a not-for-profit basis, in portions of 22 counties located in Western Kentucky. Big Rivers is unique to other generation and transmission cooperatives in that it has one Member with two large aluminum smelters in its customer base that operate at a continuous 98% load factor. However, Big Rivers does not currently provide wholesale electric service to meet the majority of that Member's Smelter load but will do so under the "Unwind". Other generation and transmission cooperatives that are currently comparable to Big Rivers in operating and financial metrics vary with the financial measure used as seen in the attached schedule.

Witness) C. William Blackburn

Comparison of Generation and Transmission (G&T) Cooperatives*:

G&T Cooperative	Total MWh Sales	Total Revenue per MWh	Member MWh Sales	Member Revenue per Mwh	Total Assets	Total Operating Revenue	Total Debt	DSC Ratio	TIER	Cost of Debt
Alabama Electric Cooperative, Inc.	9,498,411	64.81	8,590,026	64.98	1,199,933,625	617,660,934	913,961,412	1.17	1.29	5.72%
Allegheny Electric Cooperative, Inc.	2,952,198	55.20	2,833,858	56.90	360,495,996	180,062,423	189,721,400	1.51	3.80	6.90%
Arizona Electric Power Cooperative, Inc.	3,490,775	NA	3,336,119	NA	279,561,295	NA	195,415,425	NA	NA	5.97%
Arkansas Electric Cooperative Corporation	13,075,407	46.28	12,018,796	47.85	1,117,608,500	605,562,276	537,788,745	1.10	1.53	5.54%
Associated Electric Cooperative, Inc.	22,397,441	38.62	17,336,688	32.77	1,821,765,076	867,142,524	1,030,129,726	1.32	1.24	6.01%
Basin Electric Power Cooperative	17,968,000	34.31	11,849,000	30.73	2,879,776,889	628,716,081	1,376,865,167	NA	1.32	5.58%
Big Rivers Electric Corporation	5,250,342	36.35	3,188,056	34.11	1,254,388,832	230,236,571	1,218,135,347	1.86	1.47	5.83%
Brazos Electric Cooperative, Inc.	11,530,377	74.03	11,363,383	75.84	1,493,901,731	880,892,682	985,388,366	1.91	2.07	4.81%
Buckeye Power, Inc.	8,231,237	41.84	7,904,419	41.59	923,957,611	354,577,815	373,603,060	1.35	2.67	5.33%
Central Electric Power - Missouri	3,253,019	35.42	3,253,019	35.42	193,552,854	116,090,344	75,004,671	1.49	2.55	5.17%
Central Electric Power - South Carolina	13,492,954	57.49	13,492,954	57.49	193,755,837	775,455,976	83,093,278	1.10	1.32	4.91%
Central Iowa Power Cooperative	2,451,023	56.54	2,451,023	56.54	462,198,104	140,111,115	298,516,814	1.17	1.61	5.73%
Central Power Electric Cooperative, Inc.	1,454,767	32.86	1,454,767	32.86	67,247,345	47,919,538	32,421,861	1.65	2.14	5.51%
Chugach Electric Association, Inc.	2,753,266	97.17	1,523,289	72.26	563,040,148	267,542,713	364,532,099	1.92	1.41	6.18%
Corn Belt Power Cooperative	1,759,562	45.23	1,713,003	45.68	308,028,349	83,914,575	176,887,184	1.15	1.07	5.06%
Dairyland Power Cooperative	6,118,651	45.02	5,463,467	46.37	945,788,755	284,439,111	586,499,324	1.16	1.51	4.42%
Deseret G&T Cooperative	5,575,711	39.23	2,075,361	38.92	474,944,836	218,755,725	318,334,595	1.10	1.33	10.63%
East Kentucky Power Cooperative	12,206,412	53.16	12,129,402	53.22	2,028,501,182	650,959,941	1,702,086,944	0.98	1.13	5.43%
East River Electric Power Cooperative, Inc.	2,408,994	32.67	2,408,994	32.67	181,601,804	85,727,358	94,755,136	1.49	2.32	4.78%
Golden Spread Electric Cooperative	6,477,751	67.32	4,923,961	69.44	341,107,480	436,106,124	152,796,433	2.65	3.55	6.28%
Great River Energy	14,665,444	46.78	11,421,473	44.52	1,980,916,000	710,031,000	1,469,885,554	1.28	1.83	5.45%
Hoosier Energy Rural Electric Cooperative, Inc.	9,923,558	44.46	6,525,739	49.65	1,042,444,450	441,344,744	808,584,000	1.30	1.20	5.30%
KAMO Electric Cooperative, Inc.	5,860,754	38.31	5,860,754	38.31	404,848,990	226,746,915	232,274,256	1.34	1.36	6.81%
Kansas Electric Power Cooperative, Inc.	1,794,728	61.72	1,790,777	61.82	206,069,092	110,774,319	153,434,985	NA	1.12	6.00%
M & A Electric Cooperative, Inc.	1,599,342	35.69	1,599,342	35.69	85,287,830	57,085,676	33,476,528	2.26	2.73	5.51%
Minnkota Power Cooperative, Inc.	3,969,952	38.80	3,080,882	35.80	206,481,413	155,275,887	95,254,151	1.44	1.75	5.52%
N.W. Electric Power	1,555,262	37.47	1,555,262	37.47	120,032,300	59,481,148	33,787,510	2.39	2.07	5.85%
Nebraska Electric G&T Cooperative	3,499,705	37.96	3,499,705	37.96	15,676,770	132,859,511	NA	NA	NA	NA
North Carolina Electric Membership Corporation	16,476,547	55.27	15,125,412	56.12	1,307,077,135	911,164,597	1,025,798,874	1.00	1.11	5.55%
Northeast Missouri Electric Power Cooperative	1,174,604	35.53	1,174,604	35.53	60,863,369	44,069,475	18,531,987	2.73	3.13	5.54%
Northeast Texas Electric Cooperative, Inc.	3,024,070	53.71	3,024,070	53.71	229,922,952	162,445,290	138,897,944	1.18	1.33	5.40%
Northwest Iowa Power Cooperative	1,214,901	30.71	955,835	32.71	65,981,341	39,732,057	23,594,434	1.34	2.49	5.92%
Oglethorpe Power Corporation	23,025,710	49.03	23,019,482	48.98	4,901,745,000	1,128,879,000	3,402,094,000	NA	1.10	5.46%
Old Dominion Electric Cooperative	12,375,757	66.06	11,026,284	67.70	1,627,409,000	817,515,000	NA	0.89	1.39	6.49%
PNGC Power	5,212,481	31.93	3,955,380	30.44	36,657,744	167,056,500	NA	NA	NA	NA
Rayburn Country Electric Cooperative, Inc.	2,929,158	77.72	2,929,158	77.72	78,115,620	222,652,052	20,837,729	2.01	2.00	NA
Rushmore Electric Power Cooperative, Inc.	930,944	31.41	930,944	31.41	25,020,998	30,067,606	NA	NA	NA	NA
Saluda River Electric Cooperative	4,005,648	39.11	3,208,788	46.59	166,847,566	156,670,095	332,512,352	NA	NA	NA
Sam Rayburn G&T Electric Cooperative, Inc.	1,682,331	56.20	1,682,331	56.20	62,412,711	94,558,537	36,417,637	1.42	1.70	6.75%
San Miguel Electric Cooperative, Inc.	2,937,194	34.35	2,937,194	34.35	229,949,694	104,447,074	170,226,076	1.46	1.35	4.52%
Seminole Electric Cooperative, Inc.	17,006,749	68.48	16,777,086	68.59	1,410,567,844	1,173,424,620	1,183,706,261	1.05	1.24	5.17%
Sho-Me Power Electric Cooperative	3,923,837	39.77	2,744,628	40.20	261,235,992	169,119,453	111,344,105	2.53	3.46	5.87%
South Mississippi Electric	9,535,462	66.40	9,528,089	68.16	1,011,163,017	636,991,811	722,964,790	1.14	1.25	5.40%
South Texas Electric Cooperative, Inc.	2,332,883	57.83	2,188,796	58.64	335,644,754	150,150,084	256,171,766	1.24	1.24	5.16%
Southern Illinois Power Cooperative	2,214,165	54.99	1,883,652	56.54	341,795,877	123,818,641	280,327,488	2.19	1.68	5.15%
Soyland Power Cooperative, Inc.	1,492,128	56.04	1,492,128	56.04	84,224,676	84,950,951	48,323,194	1.36	1.19	5.93%
Square Butte Electric Cooperative	3,189,843	27.71	1,096,508	27.71	359,537,035	89,722,827	303,742,814	1.12	1.09	6.26%
Sunflower Electric Power Corporation	2,672,598	50.63	1,892,244	54.14	348,546,027	140,835,920	357,333,049	1.23	1.32	NA
Tex La Electric Cooperative of Texas	1,427,281	62.30	1,427,281	62.30	170,422,672	88,916,048	138,902,920	1.50	7.27	8.20%
Tri-State G&T Association, Inc.	16,613,736	50.50	13,094,448	49.79	2,471,415,634	846,044,628	1,772,601,989	1.11	NA	6.10%
Upper Missouri G&T	1,637,014	27.52	1,392,126	27.05	30,258,136	45,042,736	8,876,421	NA	5.41	6.76%
Wabash Valley Power Association, Inc.	11,819,056	47.13	8,338,572	49.12	488,407,378	569,041,251	330,625,388	1.24	1.23	5.33%
Western Farmers Electric Cooperative	6,674,093	57.75	6,250,641	58.39	790,728,459	402,149,402	620,706,240	1.11	1.33	6.06%
Wolverine Power Supply Cooperative	3,363,984	58.17	3,120,623	NA	223,598,350	195,689,229	90,570,413	NA	4.30	5.48%

* Highlighted amounts represents those G&T's comparable to Big Rivers

Source: G&T Accounting & Finance Association Annual Directory - June 2007 (2006 Data)

Item 21) State the current interest rates on long term debt that Big Rivers believes it could achieve, in the circumstance in which it possessed "investment grade" credit ratings. Also state the credit rating assumed for purposes of providing this current interest rate, e.g., BBB, A, etc.

Response)

Investment Grade (BBB Rating)

Term	Indicative Rate	Benchmark UST Rate	Spread to UST (bp)
2	4.09	1.99	210
3	4.35	2.25	210
5	4.87	2.77	210
10	5.88	3.73	215
30	6.85	4.50	235

Witness) C. William Blackburn
Mark Glotfelty

Item 22) State the current interest rates on long term debt that Big Rivers believes it could achieve, in the circumstance in which it possessed "non-investment grade" credit ratings. Also state the credit rating assumed for purposes of providing this current interest rate, e.g., BBB, B, etc.

Response)

Sub-Investment Grade (BB Rating)

Indicative Rate	Benchmark UST Rate	Spread to UST (bp)
8.75	2.77	598
8.75	2.77	598
8.75	2.77	598
9.00	3.73	527
9.50	4.50	500

Witness) C. William Blackburn
Mark Glotfelty

Item 23) Provide a sensitivity run of the financial model (Exhibit 8), varying only the assumed interest rates on long term debt to be those consistent with "non-investment grade" credit ratings. Please provide the electronic spreadsheet file version of this sensitivity run, including a description of inputs that were varied to produce it.

Response) We have included a sensitivity run of the Financial Model varied to assume interest rates on long term debt to be those consistent with BB credit ratings, which are non-investment grade. Please note that, as described in the testimony of C. William Blackburn, one condition to the closing of the Unwind Transaction is Big Rivers obtaining an investment grade rating from Moody's and Standard and Poor's.

Key changes in inputs are provided in the Table attached.

Witness) C. William Blackburn
Robert S. Mudge

Projected Interest Rates and Related Costs (%)
(estimates provided by Goldman Sachs)

		Indicative Rates (Coupon), by Maturity		
Rating Category		BBB *		BB **
Investment Grade		Y		N
Insurance		Y	N	N
Insurance Premium		0.80	na	na
May 2007				
	2	5.42	5.95	7.30
	3	5.34	5.87	7.22
	5	5.18	5.71	7.06
	10	5.32	5.90	7.30
	30	5.64	6.32	7.67
February 2008				
	2	na	4.09	8.75
	3	na	4.35	8.75
	5	na	4.87	8.75
	10	na	5.88	9.00
	30	na	6.85	9.50

* Encompassing BBB- to BBB+
** Encompassing BB- to BB+

Current non-investment grade

<u>AG 23</u>

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December 2007

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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	
I. Sales (TWH)																			
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
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
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
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
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
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

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 ($/ MWH Sold, unless otherwise noted)																			
General Rate Adjustment (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	6.31%	0.00%	0.00%	0.00%	0.00%	0.00%	10.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
FAC ($/ 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 ($/ MWH)				(0.54)	0.05	(0.37)	0.73	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
Environmental Surcharge Adjustment ($/ 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 ($/ KW-mo.)	7.37	7.37		7.37	7.37	7.37	7.84	7.84	7.84	7.84	7.84	7.84	8.64	8.64	8.64	8.64	8.64	8.64	8.64
Energy ($/ MWH)	20.40	20.40		20.40	20.40	20.40	21.69	21.69	21.69	21.69	21.69	21.69	23.91	23.91	23.91	23.91	23.91	23.91	23.91
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				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
GRA	-	-		-	-	-	2.35	2.34	2.34	2.34	2.34	2.34	6.38	6.37	6.37	6.37	6.36	6.36	6.36
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
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)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.00	-	-	0.49	7.03	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	36.12	36.12	38.46	38.94	45.66	46.56	47.78	48.64	52.08	52.62	52.97	53.70	54.15	54.78	55.05
TIER Related Rebate	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	34.96	36.79		36.07	36.12	36.12	38.46	38.94	45.66	46.56	47.78	48.64	52.08	52.62	52.97	53.70	54.15	54.78	55.05
Large Industrial																			
Load Factor (%)	80.2%	78.1%		78.1%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.4%	78.6%	78.6%	78.6%	78.3%	78.6%	78.6%	78.6%
Demand ($/ KW-mo.)	10.15	10.15		10.15	10.15	10.15	10.79	10.79	10.79	10.79	10.79	10.79	11.90	11.90	11.90	11.90	11.90	11.90	11.90
Energy ($/ MWH)	13.72	13.72		13.72	13.72	13.72	14.58	14.58	14.58	14.58	14.58	14.58	16.08	16.08	16.08	16.08	16.08	16.08	16.08
Base	31.06	31.52		31.52	31.39	31.39	31.39	31.40	31.39	31.39	31.39	31.41	31.39	31.39	31.39	31.42	31.39	31.39	31.39
Power Factor Penalty/ Demand Cr. (L	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
MRDA	(0.99)	(2.85)		(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
Regulatory Account Charge				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
GRA	-	-		-	-	-	1.98	1.98	1.98	1.98	1.98	1.98	5.41	5.41	5.41	5.41	5.41	5.41	5.41
FAC	-	-		5.90	5.84	7.05	7.60	7.81	8.31	8.99	9.01	9.41	9.45	9.75	9.64	10.11	10.30	10.39	10.44
Environmental Surcharge	-	-		0.49	0.85	2.68	2.62	2.89	2.89	3.02	4.14	4.17	4.12	4.28	4.25	4.45	4.63	4.65	4.82
Surcredit	-	-		(4.00)	(2.95)	(3.87)	(3.77)	(4.28)	(4.17)	(4.08)	(3.98)	(3.90)	(4.49)	(4.40)	(4.30)	(4.22)	(4.12)	(4.04)	(3.96)
Economic Reserve	-	-		(2.39)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
Net	-	-		(0.00)	0.00	-	-	0.49	7.03	7.94	9.17	9.68	9.08	9.64	9.58	10.34	10.81	11.00	11.30
Pre TIER Rebate Total	30.07	28.67		30.58	30.46	30.48	32.49	33.00	39.73	40.65	41.89	42.80	45.62	46.19	46.56	47.34	47.78	48.42	48.72
TIER Related Rebate	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Effective Rate ($/ MWH)	30.07	28.67		30.58	30.46	30.48	32.49	33.00	39.73	40.65	41.89	42.80	45.62	46.19	46.56	47.34	47.78	48.42	48.72

	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				-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
75	GRA	-	-		-	-	-	2.23	2.23	2.23	2.23	2.23	2.23	6.07	6.07	6.06	6.06	6.06	6.05	6.05
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)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
81	Net				(0.00)	0.00	-	-	0.49	7.03	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	34.40	34.39	36.62	37.10	43.81	44.70	45.93	46.80	50.03	50.57	50.92	51.66	52.11	52.73	53.01
84	TIER Related Rebate	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
85	*Effective Rate*	33.55	34.37		34.44	34.40	34.39	36.62	37.10	43.81	44.70	45.93	46.80	50.03	50.57	50.92	51.66	52.11	52.73	53.01
86																				
87	Smelters																			
88	Base Rate	-	-		27.32	27.33	27.34	29.12	29.10	29.16	29.18	29.19	29.17	32.27	32.28	32.30	32.27	32.32	32.34	32.35
89	TIER Adjustment	-	-		1.57	1.18	0.63	1.80	2.60	2.32	2.15	3.52	3.21	3.14	0.13	3.11	2.08	3.35	2.36	3.29
90	Smelter Rate Subject to Price Cap	-	-		28.89	28.51	27.98	30.93	31.70	31.48	31.33	32.71	32.38	35.41	32.41	35.41	34.35	35.67	34.70	35.63
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	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
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	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
97	Effective Rate	-	-		36.64	36.66	39.24	43.78	45.05	45.69	45.84	48.61	48.66	53.31	49.67	53.41	52.61	54.71	54.00	55.73
98																				
99	Market	55.81	37.82		48.40	51.34	49.47	50.22	48.34	51.48	51.92	53.69	52.59	53.75	54.70	57.55	57.70	56.11	59.94	59.12
100																				
101	Overall Blend	39.26	35.74		37.53	37.80	39.17	42.33	42.95	45.66	46.06	48.20	48.39	52.23	50.37	52.76	52.56	53.84	53.85	54.90
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	88.1	89.8	97.8	101.0	121.0	125.9	132.0	137.1	149.9	154.5	158.8	164.3	169.0	174.2	178.5
107	Large Industrial	29.3	9.3	-	21.1	32.4	33.4	36.8	38.5	47.7	50.2	53.2	55.8	61.0	63.4	65.5	68.2	70.5	73.1	75.3
108	Smelters	-	-	-	179.5	267.5	286.3	319.4	329.7	333.4	334.5	354.7	356.1	389.0	362.4	389.7	385.0	399.2	394.0	406.7
109	Offsystem	64.9	26.9	-	51.4	76.7	79.8	66.3	58.5	61.7	60.8	60.0	56.9	49.2	54.0	40.0	41.4	42.0	41.0	41.4
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	4.6	4.365	4.6	5.0	5.5	6.0	6.8	7.5	8.2	8.9	9.6	10.2
116	Total Receipts	239.9	84.398	-	330.0	491.1	493.8	526.5	533.3	569.6	576.9	595.8	603.0	647.7	633.2	654.8	659.3	681.5	684.0	703.3
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	27.5	31.9	25.8	29.0	28.6	43.7	30.3	40.9	36.2	41.5	43.7	51.3
122	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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)	-	(22.4)	(0.5)	(1.7)	(1.3)	(0.2)	0.8	(0.8)	(1.3)	(0.6)	(1.1)	0.7	(1.6)	(0.5)	(1.7)	(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	-	238.9	393.3	407.6	436.0	439.1	460.7	459.5	478.1	484.5	520.5	500.9	523.0	527.0	549.3	554.5	573.9
134																				
135	Operating Receipts less Disbursements	113.6	34.4	-	91.2	97.8	86.2	90.6	94.2	108.9	117.4	117.7	118.5	127.2	132.3	131.7	132.3	132.2	129.5	129.4
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	
Operating Receipts less Disbursements	113.6	34.4	-	91.2	97.8	86.2	90.6	94.2	108.9	117.4	117.7	118.5	127.2	132.3	131.7	132.3	132.2	129.5	129.4
Capital Expenditures																			
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
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
Transmission Upgrades	4.1	-	-	3.7	6.0	1.7	-	-	-	-	-	-	-	-	-	-	-	-	-
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
Extraordinary Generation	-	-	-	7.6	21.3	20.9	20.4	13.6	1.6	3.0	-	-	-	1.8	4.1	0.9	-	-	-
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
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
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
Net Pre-Finance Cash Flow	91.2	26.5	-	53.7	21.7	27.6	34.3	40.3	73.3	79.6	80.1	80.3	86.8	86.2	84.2	86.6	84.4	82.1	80.1
Financing																			
Principal	12.5	13.0	-	11.1	17.2	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.8	35.8	39.2
Interest	36.7	16.9	-	34.6	51.1	50.1	49.1	48.0	46.8	45.5	44.2	42.8	41.3	39.7	38.1	36.3	34.5	32.5	29.1
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
Aggregate Debt Service (incl. Line	49.2	30.0	-	46.1	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8
Post-Finance Cash Flow	42.0	(3.5)	-	7.7	(47.1)	(41.2)	(34.5)	(28.5)	4.5	10.8	11.3	11.5	17.9	17.4	15.4	17.8	15.6	13.3	11.3
Unwind Transaction																			
Cash Proceeds			301.5																
Debt Reduction			(195.8)																
Misc. Transaction			(5.6)																
Net Before Member Reserves			100.1																
Economic Reserve			(75.0)	5.5	13.1	21.0	23.7	22.3	-	-	-	-	-	-	-	-	-	-	-
Net Before Transition Reserve			25.1	5.5	13.1	21.0	23.7	22.3	-	-	-	-	-	-	-	-	-	-	-
Ending Cash Balances (Incl. Transition Reserve)	138.4	134.9	160.0	173.2	139.2	119.0	108.2	102.0	106.5	117.3	128.5	140.0	158.0	175.4	190.8	208.6	224.2	237.5	248.7

	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	
171	**IV. Income Statement (M$)**																			
172																				
173	Revenues																			
174	Rural	83.8	28.0	-	58.9	88.1	89.8	97.8	101.0	121.0	125.9	132.0	137.1	149.9	154.5	158.8	164.3	169.0	174.2	178.5
175	Large Industrial	29.3	9.3	-	21.1	32.4	33.4	36.8	38.5	47.7	50.2	53.2	55.8	61.0	63.4	65.5	68.2	70.5	73.1	75.3
176	Smelters	-	-	-	179.5	267.5	286.3	319.4	329.7	333.4	334.5	354.7	356.1	389.0	362.4	389.7	385.0	399.2	394.0	406.7
177	Off-System	64.9	26.9	-	51.4	76.7	79.8	66.3	58.5	61.7	60.8	60.0	56.9	49.2	54.0	40.0	41.4	42.0	41.0	41.4
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	7.414	5.959	5.094	4.630	4.365	4.558	5.019	5.501	5.993	6.761	7.506	8.165	8.928	9.594	10.163
183	Total Revenues	243.9	85.8	-	329.7	490.5	493.3	526.0	532.8	569.0	576.4	595.3	602.4	647.1	632.7	654.2	658.7	681.0	683.4	702.7
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	25.8	29.5	25.3	27.4	28.7	38.5	29.7	38.2	35.3	38.6	42.1	46.8
189	Carbon Tax			-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	-	38.7	57.7	57.1	56.5	55.9	54.9	54.1	53.3	52.5	51.5	50.5	49.5	48.5	47.3	46.0	43.2
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	-	322.8	485.0	498.2	530.9	536.3	550.2	557.5	576.3	583.4	628.1	613.5	635.1	639.4	661.6	664.0	683.6
204																				
205	Unwind Transaction	-	-	622.7	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
206																				
207	Economic Reserve	-	-	*(75.0)*	5.5	*13.1*	*21.0*	*23.7*	22.3	-	-	-	-	-	-	-	-	-	-	-
208																				
209	Net Margin	37.6	8.9	547.7	12.4	18.6	16.1	18.7	18.8	18.8	18.9	18.9	19.0	19.0	19.1	19.2	19.3	19.3	19.5	19.2

Row		2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	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	137.2	101.7	79.9	67.4	59.4	62.1	71.0	80.3	89.7	105.5	120.6	133.7	149.1	162.1	172.7	181.2
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	61.6	43.2	21.4	-	-	-	-	-	-	-	-	-	-	-	-
224	Accounts Receivable	17.7	17.7	17.7	40.5	40.3	40.6	43.4	44.0	47.1	47.7	49.2	49.7	53.4	52.2	53.9	54.2	56.0	56.2	57.7
225	Regulatory Asset	-	-	-	-	-	-	0.3	2.0	4.4	5.0	6.5	6.4	11.6	12.1	14.8	15.7	18.6	20.2	24.8
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	15.2	15.2	14.8	14.4	14.0	13.5	15.7	15.1	14.5	13.8	13.1	12.4	11.6	10.8	9.9	12.2	11.3
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	1,570.5	1,622.1	1,618.7	1,614.2	1,607.0	1,598.4	1,612.4	1,625.4	1,639.8	1,652.4	1,668.6	1,678.0	1,692.5	1,704.5	1,719.0	1,730.6	1,743.3
236																				
237	Liabilities & Equities																			
238	Margins & Equities	(179.8)	(170.9)	376.9	389.3	407.9	424.1	442.8	461.6	480.5	499.3	518.2	537.2	556.3	575.4	594.6	613.8	633.2	652.6	671.8
239	Long-Term Debt																			
240	Existing Debt	1,062.1	1,051.1	861.3	854.2	843.4	832.0	819.9	807.1	793.5	779.2	764.0	747.9	730.9	712.9	693.8	673.6	652.3	629.6	604.4
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	1,047.6	1,045.2	1,035.8	1,033.0	1,029.9	1,025.8	1,021.6	1,017.2	1,012.7	1,008.1	1,003.3	998.3	993.3	988.1	982.8	977.3	970.5
243	Current & Accrued Liabilities																			
244	Accounts Payable	11.7	11.7	11.7	57.2	57.3	59.1	63.1	63.8	65.8	67.0	69.6	70.5	75.1	72.9	76.0	76.6	79.8	80.1	83.2
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	61.6	43.2	21.4	-	-	-	-	-	-	-	-	-	-	-	-
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				-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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	1,570.5	1,622.1	1,618.7	1,614.2	1,607.0	1,598.4	1,612.4	1,625.4	1,639.8	1,652.4	1,668.6	1,678.0	1,692.5	1,704.5	1,719.0	1,730.6	1,743.3
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	
Change in Working Capital																			
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
Accounts Receivable	0.3	-	-	22.7	(0.2)	0.4	2.8	0.6	3.0	0.6	1.5	0.6	3.7	(1.3)	1.7	0.3	1.8	0.2	1.6
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
Other Current Assets	0.6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Accounts Payable	0.9	-	-	(45.5)	(0.1)	(1.8)	(4.0)	(0.7)	(2.0)	(1.2)	(2.6)	(0.9)	(4.6)	2.2	(3.1)	(0.6)	(3.2)	(0.3)	(3.1)
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)
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)
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)
Net SLB	(0.3)	(0.1)																	
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)
Adjustment	0.2	0.0		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	1.6	(0.6)	-	(22.4)	(0.5)	(1.7)	(1.3)	(0.2)	0.8	(0.8)	(1.3)	(0.6)	(1.1)	0.7	(1.6)	(0.5)	(1.7)	(0.4)	(1.8)
Cash Balance																			
Beginning	96.5	138.4	134.9	160.0	173.2	139.2	119.0	108.2	102.0	106.5	117.3	128.5	140.0	158.0	175.4	190.8	208.6	224.2	237.4
Ending	138.4	134.9	160.0	173.2	139.2	119.0	108.2	102.0	106.5	117.3	128.5	140.0	158.0	175.4	190.8	208.6	224.2	237.4	248.7
VI. Credit Measures																			
Contract TIER																			
Earnings				12.4	18.6	16.1	18.7	18.8	18.8	18.9	18.9	19.0	19.0	19.1	19.2	19.3	19.3	19.5	19.2
Plus: Interest Expense, Financing Fees, and Restucturing				38.8	57.9	57.3	56.6	56.0	55.2	54.4	53.6	52.8	51.8	50.8	49.8	48.8	47.6	46.5	43.6
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				50.2	75.0	74.3	73.7	73.1	72.2	71.3	70.5	69.7	68.7	67.7	66.6	65.6	64.4	63.3	60.0
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				59.1	88.3	88.2	88.2	88.1	87.9	87.7	87.5	87.5	87.2	87.1	87.0	87.0	86.7	86.8	84.7
Divided by																			
Interest Expense, Financing Fees, and Restructuring				38.8	57.9	57.3	56.6	56.0	55.2	54.4	53.6	52.8	51.8	50.8	49.8	48.8	47.6	46.5	43.6
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				47.6	71.2	71.2	71.1	71.1	70.9	70.7	70.6	70.5	70.4	70.3	70.1	70.1	70.0	70.0	68.3
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
Conventional TIER																			
Earnings				12.4	18.6	16.1	18.7	18.8	18.8	18.9	18.9	19.0	19.0	19.1	19.2	19.3	19.3	19.5	19.2
Plus: Interest Expense, Financing Fees, and Restucturing				38.8	57.9	57.3	56.6	56.0	55.2	54.4	53.6	52.8	51.8	50.8	49.8	48.8	47.6	46.5	43.6
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
Total				51.2	76.5	73.4	75.4	74.8	74.7	73.9	73.2	72.5	71.6	70.7	69.8	68.9	67.8	66.9	63.8
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				60.1	89.8	87.3	89.9	89.9	90.4	90.2	90.2	90.3	90.2	90.1	90.1	90.2	90.2	90.4	88.5
Divided by																			
Interest Expense, Financing Fees, and Restructuring				38.8	57.9	57.3	56.6	56.0	55.2	54.4	53.6	52.8	51.8	50.8	49.8	48.8	47.6	46.5	43.6
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				47.6	71.2	71.2	71.1	71.1	70.9	70.7	70.6	70.5	70.4	70.3	70.1	70.1	70.0	70.0	68.3
Conventional TIER				1.26	1.26	1.23	1.26	1.26	1.27	1.28	1.28	1.28	1.28	1.28	1.29	1.29	1.29	1.29	1.29

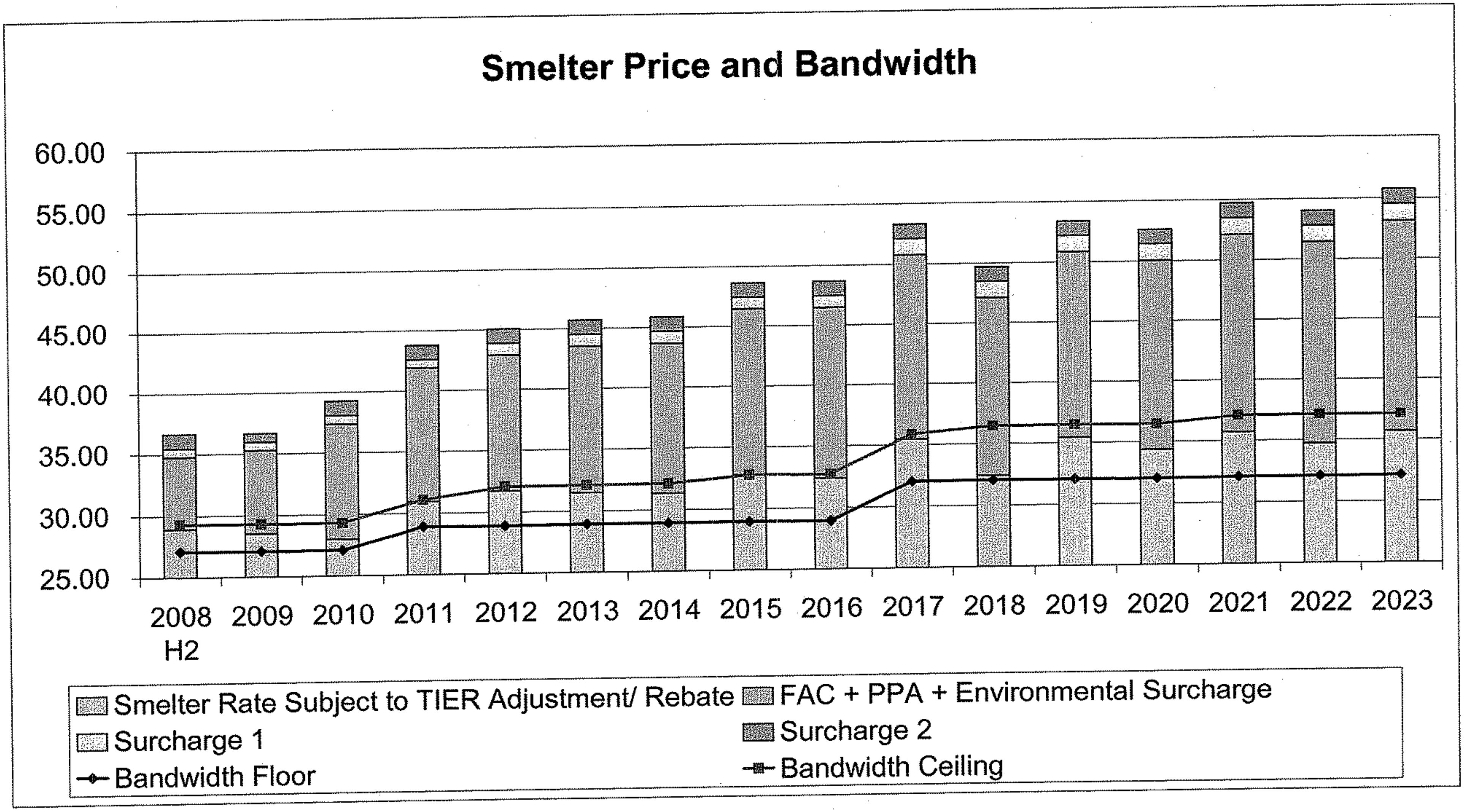
	Calendar Year	2007	2008H1	Transaction	2008 H2	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	0.000	0.000	0.000	0.669	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000
	Pre-Transaction Allocation	1.000	0.331	0.000	0.000	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				91.2	97.8	86.2	90.6	94.2	108.9	117.4	117.7	118.5	127.2	132.3	131.7	132.3	132.2	129.5	129.4
309	Economic Reserve				5.5	13.1	21.0	23.7	22.3	-	-	-	-	-	-	-	-	-	-	-
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				96.7	110.8	107.2	114.2	116.5	108.9	117.0	117.4	118.1	126.8	131.9	131.3	131.8	131.7	129.0	128.8
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				105.6	124.2	121.1	128.7	131.5	124.5	133.4	134.4	135.9	145.4	151.3	151.6	153.1	154.1	152.5	153.5
314	Divided by																			
315	Interest Expenditures				35.0	51.6	50.6	49.6	48.5	47.3	46.0	44.7	43.3	41.8	40.2	38.6	36.8	35.0	33.0	29.6
316	Scheduled Principal				11.1	17.2	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.8	35.8	39.2
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				54.9	82.1	82.7	83.3	83.9	84.5	85.1	85.8	86.6	87.4	88.2	89.2	90.1	91.2	92.3	93.5
319																				
320	*DSCR*				1.92	1.51	1.46	1.55	1.57	1.47	1.57	1.57	1.57	1.66	1.71	1.70	1.70	1.69	1.65	1.64
321																				
322	Days Cash on Hand																			
323	Average Cash Balance	117.5	136.7	147.5	166.6	156.2	129.1	113.6	105.1	104.2	111.9	122.9	134.3	149.0	166.7	183.1	199.7	216.4	230.8	243.1
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	233.5	256.2	229.1	213.6	205.1	204.2	211.9	222.9	234.3	249.0	266.7	283.1	299.7	316.4	330.8	343.1
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	25.8	29.5	25.3	27.4	28.7	38.5	29.7	38.2	35.3	38.6	42.1	46.8
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. Financing	60.0	19.3	-	38.7	57.7	57.1	56.5	55.9	54.9	54.1	53.3	52.5	51.5	50.5	49.5	48.5	47.3	46.0	43.2
338	Total	182.8	69.2	-	301.2	450.7	462.6	489.1	493.0	506.2	513.3	530.6	536.2	566.6	550.7	570.9	573.9	594.7	595.4	613.6
339																				
340	*Days Cash on Hand (including Line o*	234.5	721.0		283.0	207.5	180.8	159.4	151.8	147.3	150.7	153.3	159.5	160.4	176.7	181.0	190.6	194.2	202.8	204.1
341	*Days Cash on Hand (excluding Line c*	234.5	721.0		201.9	126.5	101.9	84.8	77.8	75.2	79.5	84.5	91.4	96.0	110.5	117.0	127.0	132.8	141.5	144.6
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	-		-	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9
347	Principal	-		(211.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
348	Interest	-		-	13.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
349	Debt Service	-		(211.9)	13.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
350	*Blended Interest Cost*		0.00%	0.00%	6.37%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%	9.52%
351																				
352	Fixed/ Insured Serial Bonds (Tranche 2)																			
353	Beginning Principal	-		-	82.0	81.9	81.7	81.4	81.1	80.7	80.4	80.0	79.5	79.0	78.5	78.0	77.3	76.7	75.5	39.7
354	Principal	-		(82.0)	0.1	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.7	1.2	35.8	39.2
355	Interest	-		-	5.1	7.6	7.6	7.6	7.6	7.5	7.5	7.5	7.4	7.4	7.3	7.3	7.2	7.2	7.1	3.7
356	Debt Service	-		(82.0)	5.2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.4	42.9	42.9
357	Blended Interest Cost		0.00%	0.00%	6.24%	9.32%	9.32%	9.33%	9.33%	9.33%	9.34%	9.34%	9.34%	9.34%	9.34%	9.35%	9.35%	9.35%	9.35%	9.38%
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	325.0	314.0	297.1	279.2	260.2	240.2	219.1	196.7	173.0	148.0	121.5	93.5	63.9	32.6	-	-
368	Principal	-		469.7	11.0	16.9	17.9	18.9	20.0	21.2	22.4	23.7	25.0	26.5	28.0	29.6	31.3	32.6	-	-
369	Interest	-		-	12.5	18.1	17.1	16.1	15.0	13.8	12.6	11.3	9.9	8.5	7.0	5.4	3.7	1.9	-	-
370	Debt Service	-		469.7	23.5	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	34.5	-	-
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	-		-	3.5	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
384	Debt Service	-		-	3.5	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
385	Blended Interest Cost			0.00%	2.48%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
386																				
387	Total (Incorporates RUS on Stated Basis)																			
388	Beginning Principal	-		1,038.3	862.5	855.5	844.5	832.9	820.7	807.8	794.1	779.6	764.3	748.2	731.1	713.0	693.9	673.6	652.3	629.6
389	Principal	-		175.8	11.1	17.2	18.2	19.2	20.4	21.5	22.8	24.1	25.5	27.0	28.6	30.2	32.0	33.8	35.8	39.2
390	Interest	-		-	34.6	51.1	50.1	49.1	48.0	46.8	45.5	44.2	42.8	41.3	39.7	38.1	36.3	34.5	32.5	29.1
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	-		175.8	46.1	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8	68.8

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%	6.31%	0.00%	0.00%	0.00%	0.00%	0.00%	10.27%	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	10.79	10.79	10.79	10.79	10.79	10.79	11.90	11.90	11.90	11.90	11.90	11.90	11.90
13 Energy ($/ MWH)	13.72	13.72	13.72	14.58	14.58	14.58	14.58	14.58	14.58	16.08	16.08	16.08	16.08	16.08	16.08	16.08
14 Power Factor Penalty/ Demand Cr. ($/ MWH)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
15 MRDA ($/ MWH)	(0.94)	(0.93)	(0.91)	(0.89)	(0.87)	(0.85)	(0.83)	(0.81)	(0.80)	(0.78)	(0.76)	(0.75)	(0.73)	(0.71)	(0.70)	(0.69)
16 Regulatory Account Charge	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
17 Less: Regulatory Account Charge	-	-	-	-	-	(0.17)	(0.17)	(0.16)	(0.53)	(0.52)	(0.51)	(0.92)	(0.90)	(0.88)	(1.32)	(1.30)
18 Net Rate ($/ MWH)	30.58	30.46	30.48	32.49	32.52	32.53	32.54	32.56	32.60	36.02	36.04	36.06	36.10	36.09	36.10	36.12
19																
20 Large Industrial Rate @ 98% LF	27.07	27.08	27.09	28.87	28.85	28.91	28.93	28.94	28.92	32.02	32.03	32.05	32.02	32.07	32.09	32.10
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	29.12	29.10	29.16	29.18	29.19	29.17	32.27	32.28	32.30	32.27	32.32	32.34	32.35
23 Plus TIER Adjustment	1.57	1.18	0.63	1.80	2.60	2.32	2.15	3.52	3.21	3.14	0.13	3.11	2.08	3.35	2.36	3.29
24 Less TIER Related Rebate	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
25 Smelter Rate Subject to TIER Adjustment	28.89	28.51	27.98	30.93	31.70	31.48	31.33	32.71	32.38	35.41	32.41	35.41	34.35	35.67	34.70	35.63
26																
27 Plus FAC + PPA + Environmental Surcharge	5.85	6.74	9.36	10.95	11.16	12.00	12.32	13.70	14.08	15.30	14.66	15.40	15.67	16.44	16.70	17.50
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)	36.64	36.66	39.24	43.78	45.05	45.69	45.84	48.61	48.66	53.31	49.67	53.41	52.61	54.71	54.00	55.73
31																
32 TIER Adjustment Cap ($/ MWh)																
33 Bandwidth Floor	27.32	27.33	27.34	29.12	29.10	29.16	29.18	29.19	29.17	32.27	32.28	32.30	32.27	32.32	32.34	32.35
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	31.07	32.05	32.11	32.13	32.74	32.72	35.82	36.43	36.45	36.42	37.07	37.09	37.10
36 Smelter Rate Subject to TIER Adjustment/ Rebate	28.89	28.51	27.98	30.93	31.70	31.48	31.33	32.71	32.38	35.41	32.41	35.41	34.35	35.67	34.70	35.63


Smelter Price and Bandwidth
60.00
55.00
50.00
45.00
40.00
35.00
30.00
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

TIER Adjustment Rebate/Charge																
Pre-TIER Rebate Member Revenues	80.0	120.4	123.3	134.5	139.5	168.7	176.1	185.2	192.9	210.9	217.9	224.3	232.4	239.5	247.4	253.7
Pre-TIER Adj/Rebate Smelter Revenues	171.7	258.9	281.7	306.3	310.7	316.4	318.8	329.0	332.5	366.1	361.5	367.0	369.7	374.8	376.8	382.7
Other Revenues	75.8	115.7	104.7	95.7	85.9	66.9	65.8	55.4	53.5	47.2	52.4	40.3	41.3	42.3	42.1	42.4
Pre TIER Adj/Rebate Revenues	327.5	495.0	509.7	536.5	536.1	552.1	560.7	569.6	578.9	624.2	631.7	631.5	643.5	656.6	666.2	678.8
Total Expenses	322.8	485.0	498.2	530.9	536.3	550.2	557.5	576.3	583.4	628.1	613.5	635.1	639.4	661.6	664.0	683.6
Net Margin Before TIER Adjustment	4.7	10.0	11.5	5.6	(0.2)	1.9	3.2	(6.7)	(4.5)	(3.9)	18.2	(3.5)	4.0	(5.1)	2.2	(4.8)
Interest + Margin	52.4	81.2	82.7	76.7	70.9	72.8	73.9	63.8	66.0	66.5	88.4	66.6	74.1	64.9	72.2	63.5
Interest Charges	47.6	71.2	71.2	71.1	71.1	70.9	70.7	70.6	70.5	70.4	70.3	70.1	70.1	70.0	70.0	68.3
Pre-TIER Adjustment TIER	1.10	1.14	1.16	1.08	1.00	1.03	1.04	0.90	0.94	0.94	1.26	0.95	1.06	0.93	1.03	0.93
Increment needed for 1.24x TIER	6.7	7.1	5.6	11.5	17.3	15.1	13.8	23.7	21.4	20.8	(1.3)	20.4	12.8	21.9	14.6	21.2
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.	7.7	8.6	4.6	13.2	19.0	17.0	15.7	25.7	23.5	22.9	0.9	22.7	15.2	24.4	17.2	24.0
Rebate Amount ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge ($M)	7.7	8.6	4.6	13.2	19.0	17.0	15.7	25.7	23.5	22.9	0.9	22.7	15.2	24.4	17.2	24.0
Rebate to Members/Smelters ($/MWh)																
Rurals	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Large Industrials	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Smelters	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIER Adjustment Charge to Smelters ($/MWh)	1.57	1.18	0.63	1.80	2.60	2.32	2.15	3.52	3.21	3.14	0.13	3.11	2.08	3.35	2.36	3.29

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 ($/ KW-mo.)	7.37	7.37	7.37	7.84	7.84	7.84	7.84	7.84	7.84	8.64	8.64	8.64	8.64	8.64	8.64	8.64
10	Energy ($/ MWH)	20.40	20.40	20.40	21.69	21.69	21.69	21.69	21.69	21.69	23.91	23.91	23.91	23.91	23.91	23.91	23.91
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	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
14	GRA	-	-	-	2.35	2.34	2.34	2.34	2.34	2.34	6.38	6.37	6.37	6.37	6.36	6.36	6.36
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Economic Reserve	(2.39)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
20	Net	(0.00)	0.00	-	-	0.49	7.03	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	36.12	36.12	38.46	38.94	45.66	46.56	47.78	48.64	52.08	52.62	52.97	53.70	54.15	54.78	55.05
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 ($/ KW-mo.)	10.15	10.15	10.15	10.79	10.79	10.79	10.79	10.79	10.79	11.90	11.90	11.90	11.90	11.90	11.90	11.90
26	Energy ($/ MWH)	13.72	13.72	13.72	14.58	14.58	14.58	14.58	14.58	14.58	16.08	16.08	16.08	16.08	16.08	16.08	16.08
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	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
30	GRA	-	-	-	1.98	1.98	1.98	1.98	1.98	1.98	5.41	5.41	5.41	5.41	5.41	5.41	5.41
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	Economic Reserve	(2.39)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
36	Net	(0.00)	0.00	-	-	0.49	7.03	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	30.46	30.48	32.49	33.00	39.73	40.65	41.89	42.80	45.62	46.19	46.56	47.34	47.78	48.42	48.72
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	-	-	-	-	-	0.17	0.17	0.16	0.53	0.52	0.51	0.92	0.90	0.88	1.32	1.30
43	GRA	-	-	-	2.23	2.23	2.23	2.23	2.23	2.23	6.07	6.07	6.06	6.06	6.06	6.05	6.05
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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Economic Reserve	(2.39)	(3.74)	(5.86)	(6.44)	(5.94)	-	-	-	-	-	-	-	-	-	-	-
49	Net	(0.00)	0.00	-	-	0.49	7.03	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	36.62	37.10	43.81	44.70	45.93	46.80	50.03	50.57	50.92	51.66	52.11	52.73	53.01
51																	
52	***Revenues Delta($M)***																
53	Rural	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	LI	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
56																	
57	**Smelter Rebate Lag**																
58	TWh	4.90	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30	7.32	7.30	7.30	7.30
59	Accrued ($/ MWh)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
60	Realized ($/ MWh)		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
61	Adjust ($M)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

		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	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
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)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
8	Total	1.26	(0.17)	1.33	(2.69)	(1.72)	(3.11)	(1.20)	(2.23)	(2.09)	(7.32)	(2.69)	(6.70)	(5.01)	(6.93)	(7.83)	(10.72)
9																	
10	2. Recognition of Prior Year Balance (Set to Start in 2013)																
11	Credit Member Revenue (Charge to Members)						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
12	Debit Power Purchase Expense						0.66	0.66	0.66	2.18	2.18	2.18	4.03	4.03	4.03	6.21	6.21
13																	
14	Net Income	(1.26)	0.17	(1.33)	2.69	1.72	3.11	1.20	2.23	2.09	7.32	2.69	6.70	5.01	6.93	7.83	10.72
15																	
16	**Balance Sheet**																
17	Assets																
18	Cash						0.66	1.33	1.99	4.17	6.35	8.52	12.56	16.59	20.62	26.83	33.04
19	Regulatory Asset	-	-	-	0.27	1.99	4.43	4.97	6.53	6.44	11.58	12.10	14.76	15.74	18.63	20.25	24.76
20	Total	-	-	-	0.27	1.99	5.10	6.30	8.52	10.61	17.93	20.62	27.32	32.33	39.26	47.08	57.80
21																	
22	Liabilities & Equity																
23	Equity	(1.3)	(1.1)	(2.4)	0.3	2.0	5.1	6.3	8.5	10.6	17.9	20.6	27.3	32.3	39.3	47.1	57.8
24	Regulatory Liability	1.3	1.1	2.4	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Total	-	-	-	0.3	2.0	5.1	6.3	8.5	10.6	17.9	20.6	27.3	32.3	39.3	47.1	57.8

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 ($M)	10.01	22.11	17.26	30.53	27.15	31.59	25.51	28.67	28.27	43.33	29.93	40.57	35.90	41.20	43.34	51.02
13																	
14	Total Costs for Passthrough ($/ MWh Sold)	1.21	1.80	1.38	2.48	2.21	2.56	2.06	2.30	2.26	3.49	2.38	3.27	2.86	3.26	3.42	3.99
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	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
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	0.46	0.81	0.30	0.55	0.51	1.73	0.63	1.52	1.11	1.51	1.67	2.24
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	11.16	12.00	12.32	13.70	14.08	15.30	14.66	15.40	15.67	16.44	16.70	17.50

UW ı ransaction

($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 ı ransaction

	($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)				(182.8)	
45	Underwriting Costs	1.75%			(5.1)	
46	Bond Insurance	0.80%			(7.8)	
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				(476.7)	
71	Defease ARVP				-	
72	Issue Capital Markets Debt				293.9	
73	Net				(182.8)	
74	Ending Balance - Stated				862.5	
75	Step-Down Remaining RUS New Note to GAAP Basis:				(1.2)	
76	Ending Balance - GAAP				861.3	
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
	Unwind Allocation	0.000	0.000	0.669	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
1	A&G										
2	Labor	-	-	7.69	10.97	11.29	11.63	11.98	12.34	12.71	13.09
3	Non-Labor	-	-	6.48	9.97	10.27	10.58	10.90	11.23	11.56	11.91
4	Intellectual Property	-	-	3.68	4.03	2.65	2.76	2.49	2.56	2.98	2.72
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
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
9											
10	Property Insurance	0.4013	0.14	2.63	4.05	4.17	4.30	4.43	4.56	4.70	4.84
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
14	Transmission -- Operations	0.77	0.26	0.57	0.88	0.91	0.98	1.01	1.04	1.07	1.10
15	General Plant -- Operations	0.11	0.04	0.11	0.16	0.17	0.17	0.18	0.18	0.19	0.19
16	Total	1.9589	0.667	1.86	2.86	2.94	3.54	4.11	4.23	4.36	4.49
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
20	Baseline Non-Labor	-	0.52	1.06	1.63	1.68	1.73	1.78	1.84	1.89	1.95
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
23	Property Tax	-	0.01	0.02	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
25	Total (Real)	-	0.10	0.20	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
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
28											
29	Fixed O&M										
30											
31	Labor			29.99	43.35	45.12	46.95	48.60	50.06	51.30	52.30
32											
33	Non-Labor			29.21	36.97	41.06	41.89	39.65	50.31	41.88	53.38
34											
35	Plant Maintenance										
36	Coleman			-	0.58	0.24	0.24	-	-	-	-
37	Green			-	0.34	0.24	-	-	-	-	-
38	HMP&L			-	0.34	0.24	0.64	0.64	0.64	0.64	4.86
39	Reid			-	0.34	-	-	-	-	-	-
40	Wilson			3.10	1.90	1.24	1.57	1.24	0.76	0.45	0.80
41	Adjust for Station 2			-	(0.10)	(0.07)	(0.19)	(0.20)	(0.20)	(0.20)	(1.56)
42	Total (Real)			3.10	3.39	1.90	2.25	1.68	1.19	0.89	4.10
43	Total (Nominal)			2.19	3.71	2.14	2.61	2.00	1.46	1.12	5.35
44											
45	T/G Overhauls (Cash Flows)			2.84	9.17	-	9.25	10.46	-	6.95	-
46	T/G Overhauls (Income Statement)			2.84	9.17	-	9.25	10.46	-	6.95	-
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
53	Total Fixed O&M (to Income Statement)			64.23	93.20	88.31	100.70	100.72	101.83	101.25	111.03

		2016	2017	2018	2019	2020	2021	2022	2023
	Unwind Allocation	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
1	A&G								
2	Labor	13.49	13.89	14.31	14.74	15.18	15.63	16.10	16.59
3	Non-Labor	12.27	12.63	13.01	13.40	13.81	14.22	14.65	15.09
4	Intellectual Property	2.80	3.24	2.97	3.06	3.53	3.24	3.34	3.84
5	Intellectual Property Contingency	-	-	-	-	-	-	-	-
6	Total	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	5.16	5.31	5.47	5.64	5.81	5.98	6.16	6.34
9									
10	Property Insurance	4.98	5.13	5.28	5.44	5.61	5.78	5.95	6.13
11									
12	Property Tax								
13	Baseline	3.29	3.39	3.49	3.59	3.70	3.81	3.93	4.05
14	Transmission -- Operations	1.14	1.17	1.21	1.24	1.28	1.32	1.36	1.40
15	General Plant -- Operations	0.20	0.21	0.21	0.22	0.23	0.23	0.24	0.25
16	Total	4.63	4.76	4.91	5.05	5.21	5.36	5.52	5.69
17									
18	Transmission O&M								
19	Baseline Labor	7.24	7.46	7.69	7.92	8.15	8.40	8.65	8.91
20	Baseline Non-Labor	2.01	2.07	2.13	2.19	2.26	2.33	2.40	2.47
21	Upgrades, Phase I								
22	O&M	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
23	Property Tax	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
24	Property Ins.	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
25	Total (Real)	0.29	0.29	0.29	0.29	0.29	0.29	0.29	0.29
26	Total (Nominal)	0.39	0.40	0.42	0.43	0.44	0.45	0.47	0.48
27	Total Transmission O&M	9.65	9.93	10.23	10.54	10.86	11.18	11.52	11.86
28									
29	Fixed O&M								
30									
31	Labor	53.32	54.35	55.69	57.36	59.08	60.85	62.67	64.55
32									
33	Non-Labor	45.49	47.13	53.86	54.34	54.56	60.42	53.05	67.77
34									
35	Plant Maintenance								
36	Coleman	-	-	-	-	-	-	-	-
37	Green	-	2.58	-	-	-	-	-	-
38	HMP&L	0.64	0.64	0.64	0.64	0.64	0.64	0.64	0.64
39	Reid	-	0.87	-	-	-	-	-	-
40	Wilson	0.50	0.85	0.54	1.23	0.91	1.25	0.93	1.27
41	Adjust for Station 2	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)	(0.20)
42	Total (Real)	0.93	4.72	0.97	1.66	1.35	1.68	1.36	1.70
43	Total (Nominal)	1.25	6.54	1.39	2.44	2.03	2.62	2.19	2.81
44									
45	T/G Overhauls (Cash Flows)	6.74	19.80	-	13.46	5.91	7.82	8.44	-
46	T/G Overhauls (Income Statement)	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)	106.80	127.82	110.93	127.60	121.57	131.70	126.36	135.13
53	Total Fixed O&M (to Income Statement)	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

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		-	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9	211.9
3	Coupon		0.00%	7.71%	7.97%	8.23%	8.49%	8.75%	8.80%	8.85%	8.90%	8.95%	9.00%	9.06%	9.13%	9.19%	9.25%	9.32%	9.38%
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		-	13.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
6	Principal		(211.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Debt Service		(211.9)	13.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
8																			
9	Fixed/ Insured (Tranche 2)																		
10	Beginning Balance		-	82.0	81.9	81.7	81.4	81.1	80.7	80.4	80.0	79.5	79.0	78.5	78.0	77.3	76.7	75.5	39.7
11	Coupon		0.00%	7.71%	7.97%	8.23%	8.49%	8.75%	8.80%	8.85%	8.90%	8.95%	9.00%	9.06%	9.13%	9.19%	9.25%	9.32%	9.38%
12	Principal (%)		0.00%	0.07%	0.33%	0.35%	0.38%	0.41%	0.45%	0.49%	0.53%	0.58%	0.63%	0.69%	0.75%	0.82%	1.44%	43.68%	47.75%
13	Interest		-	5.1	7.6	7.6	7.6	7.6	7.5	7.5	7.5	7.4	7.4	7.3	7.3	7.2	7.2	7.1	3.7
14	Principal		(82.0)	0.1	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.7	1.2	35.8	39.2
15	Debt Service		(82.0)	5.2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.4	42.9	42.9
16																			
17	RUS -- GAAP																		
18	Beginning Balance		791.4	323.8	312.7	296.0	278.2	259.4	239.5	218.5	196.2	172.7	147.7	121.3	93.4	63.9	32.6	-	-
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		-	12.5	18.2	17.2	16.2	15.1	13.9	12.7	11.4	10.0	8.6	7.1	5.4	3.7	1.9	-	-
22	Principal + Accrued Interest		467.6	11.0	16.8	17.8	18.8	19.9	21.0	22.3	23.6	24.9	26.4	27.9	29.5	31.3	32.6	-	-
23	Debt Service		467.6	23.5	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	35.0	34.5	-	-
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%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
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		-	3.5	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
38	Principal		-	-	0.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
39	Debt Service		-	3.5	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3
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	861.3	854.2	843.4	832.0	819.9	807.1	793.5	779.2	764.0	747.9	730.9	712.9	693.8	673.6	652.3	629.6
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		173.7	11.1	17.1	18.0	19.1	20.2	21.4	22.7	24.0	25.4	26.9	28.5	30.2	31.9	33.8	35.8	39.2
55	Interest		-	34.6	51.3	50.3	49.2	48.1	46.9	45.6	44.3	42.9	41.4	39.8	38.1	36.4	34.5	32.5	29.1
56	Debt Service		173.7	45.7	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	68.3
57	Ending Balance		861.3	854.2	843.4	832.0	819.9	807.1	793.5	779.2	764.0	747.9	730.9	712.9	693.8	673.6	652.3	629.6	604.4
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	10.02%		(201.9)	13.5	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2	20.2
63	BB			-	201.9	201.8	201.8	201.9	202.0	202.1	202.2	202.3	202.4	202.6	202.7	202.9	203.0	203.3	203.5	203.7
64	YTM			-	13.4	20.2	20.2	20.2	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.3	20.4	20.4	20.4	20.4
65	Principal Amort.			(211.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
66	Accretion			-	(0.1)	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	0.3
67	EB			201.9	201.8	201.8	201.9	202.0	202.1	202.2	202.3	202.4	202.6	202.7	202.9	203.0	203.3	203.5	203.7	204.0
68																				
69	Fixed/ Insured (Tranche 2)																			
70	Net Borrowing and YTM	9.82%		(79.0)	5.2	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	7.9	8.4	42.9	42.9
71	BB			-	79.0	79.0	78.8	78.6	78.5	78.3	78.1	77.8	77.6	77.3	77.0	76.7	76.3	75.9	75.0	39.5
72	YTM			-	5.1	7.8	7.7	7.7	7.7	7.7	7.7	7.6	7.6	7.6	7.6	7.5	7.5	7.5	7.4	3.9
73	Principal Amort.			(82.0)	0.1	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.7	1.2	35.8	39.2
74	Accretion			-	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.2
75	EB			79.0	79.0	78.8	78.6	78.5	78.3	78.1	77.8	77.6	77.3	77.0	76.7	76.3	75.9	75.0	39.5	0.5
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			13.0	13.0	13.1	12.9	12.7	12.5	12.2	12.0	11.7	11.4	11.0	10.7	10.3	9.9	9.4	8.9	8.3
88	Amortization			-	(0.1)	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.5	0.5	0.4
89	Deferred debit - EOY			13.0	13.1	12.9	12.7	12.5	12.2	12.0	11.7	11.4	11.0	10.7	10.3	9.9	9.4	8.9	8.3	7.9
90																				
91	Interest Expense																			
92	Total Interest			-	34.6	51.3	50.3	49.2	48.1	46.9	45.6	44.3	42.9	41.4	39.8	38.1	36.4	34.5	32.5	29.1
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			-	38.8	57.6	56.9	56.3	55.6	54.7	53.8	53.0	52.1	51.2	50.2	49.1	48.0	46.8	45.5	42.8

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

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.

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 | December 2007

	Electricity Sales, Purchases, and Production	Source:	2005/ Othe	2006	2007	2008H1	Transactioi 4/30/2008	2008 H2
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
4	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		61.62%	64.32%	60.17%		60.17%
5	MW			413	425	145		310
6	Large Industrial							
7	TWH	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls + 5MW/year (		0.957	0.974	0.323		0.691
8	LF	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		78.12%	80.16%	78.09%		78.09%
9	MW			140	139	47		101
10	Alcan							
11	TWH	Smelter Retail Agreement, Section 1.1.17			0	0		2.109
12	LF	Smelter Retail Agreement, Section 1.1.17			98.00%	98.00%		98.00%
13	MW	Smelter Retail Agreement, Section 1.1.15			-	-		366
14	Century							
15	TWH	Smelter Retail Agreement, Section 1.1.16						2.789
16	LF	Smelter Retail Agreement, Section 1.1.16			98.00%	98.00%		98.00%
17	MW	Smelter Retail Agreement, Section 1.1.14						484
18								
19	Offsystem (TWh)	file: annual output - 12-15-07.xls		1.93	1.16	0.71		1.06
20								
21	Purchases & Production							
22	Purchases (TWh)							
23	Market	file: annual output - 12-15-07.xls		0.07	0.02	0.01		0.13
24	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		0.24	0.20	0.10		0.17
25	*Production (TWh)*	file: annual output - 12-15-07.xls			-	-		8.07
26	Loss Rate (%)	file: annual output - 12-15-07.xls			0.81%	0.81%		0.81%
27								
28	Fuel Consumption (MMBtu)	file: annual output - 12-15-07.xls						89.9
29								
30	Startup Costs (M$)	file: annual output - 12-15-07.xls			-	-		4.38
31								
32	Emissions							
33	SO2							
34	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		14,032
35	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		32,653
36	NOX							
37	Emitted (Tons)	file: annual output - 12-15-07.xls			-	-		4,932
38	Allocation (Tons)	file: annual output - 12-15-07.xls			-	-		4,651
39	NOX Season (Mo./Yr.)				-	-		-
40								
41	Rates							
42	Fuel ($/ MMBtu)	file: annual output - 12-15-07.xls						1.48
43	Power Purchases ($/ MWh)							
44	SEPA	Existing Transacion -Budget-Arb-2008-Rev9-11-07.xls		26.98	26.98	22.44		22.44
45	Market	file: annual output - 12-15-07.xls		67.8347	77.90	200.00		47.55
46	Variable Production ($/ MWh sales)	file: annual output - 12-15-07.xls			-	2.27		2.27
47	*SO2 Allowances ($/ Ton)*	file: annual output - 12-15-07.xls			-	778		778
48	NOX Allowances ($/ Ton)	file: annual output - 12-15-07.xls			-	763		763
49								
50	Coal used (ktons)	file: annual output - 12-15-07.xls	100%					4,072
51								
52	**Sales Rates & Related**							
53								
54	General Rate Adjustments (%)	Stipulated Inputs (subject to Commission Approval at time)						0.00%
55	Shadow 2010 Rate (0=start 2011)	Smelter Retail Agreements, Section 4.7.5(a)	1	0.02				
56	Market ($/ MWh)	file: annual output - 12-15-07.xls		43.30	42.91	37.82		48.40
57								
58	*Rural*							
59	Demand ($/ 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
68	Annual Revenue Guarantee ($/ MWh)	Smelter Retail Agreements, Section 4.7 (see formula in Smelter Rate Structure, lines 99 - 127)						1.57
69	Surcharge 1 (M$)	Smelter Retail Agreements, Section 4.11 (a)						5.11
70	Surcharge 2 ($/MWh)	Smelter Retail Agreements, Sections 4.11 (b) and (c)	0					1.20
71	Base Fixed Energy	line 11 + line 15						4.90
72	Surcharge 2 (M$)	line 70 * line 71						5.88
73								
74	Member Revenue Discount Adjustment (M$)	Amortization of Gain on Year 2000 Sale-Leaseback transaction		3.68	3.68000	1.21661		2.46
75	MRDA Ratio (Rural to Industrial)	Allocated by Base Revenue + FAC post transaction		0.73	0.74	0.24		0.74
76	Power Factor Penalty/ Demand Cr. (Lrg. Ind.)	Big Rivers Assumption		0.19	-			-
77								
78	TIER Rebate Related to Rurals ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on Smelter Retail Agreements, below)						-
79	TIER Rebate Related to Large Industrials ($M)	Big Rivers Assumption (based on Rebate available to non-Smelters based on S			-			0.00
80	*TIER Rebate Related to Smelters ($M)*	Smelter Retail Agreements, Section 4.9 (energy basis allocation)						-
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
88	Allowances	file: annual output - 12-15-07.xls						0.21
89	SO2	file: annual output - 12-15-07.xls						-

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
3	TWH	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	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	464	472	482	492	501	510	521	532	541	551	562	574	584	594	605
7	TWH	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	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	154	159	164	170	174	179	184	190	194	199	204	210	214	219	224
11	TWH	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	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	366	366	366	366	366	366	366	366	366	366	366	366	366	366	366
15	TWH	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	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	484	484	484	484	484	484	484	484	484	484	484	484	484	484	484
19	Offsystem (TWh)	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
23	Market	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	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)*	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 (%)	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%
28	Fuel Consumption (MMBtu)	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
30	Startup Costs (M$)	6.54	6.84	7.89	6.54	6.91	7.01	6.17	6.97	8.06	6.81	8.66	7.68	7.68	8.42	8.22
34	Emitted (Tons)	18,797	19,882	18,824	19,356	18,296	19,317	20,336	20,806	19,359	20,823	18,767	19,356	20,501	20,755	20,354
35	Allocation (Tons)	48,979	24,489	24,489	24,489	24,489	24,489	18,352	18,352	18,352	18,352	17,125	17,125	18,352	18,352	18,352
37	Emitted (Tons)	13,610	13,606	12,916	12,895	13,063	12,974	13,115	12,988	13,014	13,060	12,813	13,164	13,188	12,936	13,288
38	Allocation (Tons)	11,072	11,072	11,071	11,057	11,056	11,057	8,944	8,944	8,491	8,297	8,153	7,948	7,713	7,491	7,419
39	NOX Season (Mo./Yr.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
42	Fuel ($/ MMBtu)	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
44	SEPA	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	53.53	53.88	51.18	48.73	43.89	46.92	48.93	46.57	49.27	46.27	48.71	52.10	59.38	55.96	59.64
46	Variable Production ($/ MWh sales)	2.45	2.60	2.83	3.07	3.13	3.19	3.53	3.62	3.74	3.81	3.92	4.01	4.18	4.23	4.40
47	*SO2 Allowances ($/ Ton)*	853	881	818	792	747	787	907	759	618	357	146	137	134	111	105
48	NOX Allowances ($/ Ton)	2,847	2,409	2,155	1,985	1,900	1,909	1,869	1,748	1,625	1,569	1,510	1,521	1,523	1,525	1,527
50	Coal used (ktons)	5,970	6,085	5,813	5,881	5,811	5,909	5,919	5,933	5,752	5,963	5,777	5,913	5,958	5,922	5,958
54	General Rate Adjustments (%)	0.00%	0.00%	6.31%	0.00%	0.00%	0.00%	0.00%	0.00%	10.27%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
56	Market ($/ MWh)	51.34	49.47	50.22	48.34	51.48	51.92	53.69	52.59	53.75	54.70	57.55	57.70	56.11	59.94	59.12
67	Margin ($/ MWh)	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25
68	Annual Revenue Guarantee ($/ MWh)	1.18	0.63	1.80	2.60	2.32	2.15	3.52	3.21	3.14	0.13	3.11	2.08	3.35	2.36	3.29
69	Surcharge 1 (M$)	5.11	5.11	5.11	7.30	7.30	7.30	7.30	7.30	10.18	10.18	10.18	10.18	10.18	10.18	10.18
70	Surcharge 2 ($/MWh)	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	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$)	5.22	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76	8.78	8.76	8.76	8.76
74	Member Revenue Discount Adjustment (M$)	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)	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.)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	TIER Rebate Related to Rurals ($M)	(0.00)	0.00	(0.00)	0.00	-	-	-	-	-	-	-	-	-	-	-
79	TIER Rebate Related to Large Industrials ($M)	(0.00)	(0.00)	-	(0.00)	-	-	-	-	-	-	-	-	-	-	-
80	*TIER Rebate Related to Smelters ($M)*	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
87	VOM	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	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	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Inputs

#	Item	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)	(4.05)	(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	4.88	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						0.07%	0.33%	0.35%	0.38%	0.41%	0.45%	0.49%	0.53%	0.59%	0.63%	0.69%	0.75%	0.82%	1.44%	43.68%	47.75%
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						7.71%	7.97%	8.23%	8.49%	8.75%	8.80%	8.85%	8.90%	8.95%	9.00%	9.06%	9.13%	9.19%	9.25%	9.32%	9.38%
118	Fixed/ Non-Insured	Indicative Big Rivers borrowing rates, 4/23/2007, Goldman Sachs						7.71%	7.97%	8.23%	8.49%	8.75%	8.80%	8.85%	8.90%	8.95%	9.00%	9.06%	9.13%	9.19%	9.25%	9.32%	9.38%
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						3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%	3.70%
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					212																
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					324																
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		-	-	-	165.78	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
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				-	1.85	1.76	1.63	1.49	1.35	1.22	3.70	3.42	3.14	2.86	2.58	2.30	2.02	1.74	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	325.00	313.98	297.06	279.17	260.24	240.23	219.07	196.69	173.02	148.00	121.53	93.54	63.95	32.65	-	-
161	Base Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		54.46	42.64	27.99	-																
162	Interest Expense	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		45.88	46.80	14.93	-	12.51	18.05	17.08	16.05	14.96	13.81	12.60	11.31	9.95	8.51	6.99	5.38	3.68	1.88	-	-
163	Interest Payment	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		31.57	31.14	15.10	-	12.51	18.05	17.08	16.05	14.96	13.81	12.60	11.31	9.95	8.51	6.99	5.38	3.68	1.88	-	-
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	-	11.02	16.92	17.89	18.92	20.01	21.16	22.38	23.67	25.03	26.47	27.99	29.60	31.30	32.65	-	-
166	Ending Principal	Long Term Debt Schedule Actual 2006 - Budget 2007.xls		803.60	807.60	794.71	794.71	313.98	297.06	279.17	260.24	240.23	219.07	196.69	173.02	148.00	121.53	93.54	63.95	32.65	-	-	-
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																							

#	Item	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	46.96	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	5.69	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	3.64
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

December 2007

		Source:	2005/ Othe	2006	2007	2008H1	Transactior	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)	(13.08)	(21.00)	(23.67)	(22.32)	-	-	-	-	-	-	-	-	-	-	-
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	0.14	0.14	0.14	0.14	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28	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	61.6	43.2	21.4	-	-	-	-	-	-	-	-	-	-	-	-
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	Transaction	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	61.6	43.2	21.4	-	-	-	-	-	-	-	-	-	-	-
431	IE	Assumed 4.28% interest earnings rate					-	2.1	3.1	2.6	1.8	0.9	-	-	-	-	-	-	-	-	-	-	-
432	Contribution	LG&E Unwind Deal Stipulated					75.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
433	Release/ Amortization	Releases to offset FAC + ES, net of surcharge rebates					-	(5.5)	(13.1)	(21.0)	(23.7)	(22.3)	-	-	-	-	-	-	-	-	-	-	-
434	EB						75.0	71.6	61.6	43.2	21.4	-	-	-	-	-	-	-	-	-	-	-	-
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:	2005/ 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	0.69	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						-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

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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Item 24) Provide copies of each (U.S.) Equities analyst report on E. ON since January 1, 2005.

Response) See E.ON's response.

Witness) E.ON. U.S.

Item 25) Provide documents which show the current size of E.ON's U.S. markets by state as divided between retail, wholesale and other (or other/different market descriptions as applicable).

Response) See E.ON's response.

Witness) E.ON. U.S.

Item 26) Assume the Application is not approved by the Commission. Identify and describe each material harm that would occur as a result of this non-approval, and the estimated point in time at which it would occur:

a. To Big Rivers;
b. To the three member retail cooperatives;
c. To the Smelters; and,
d. To E.ON U.S.

Response) a. If the Application is not approved, Big Rivers will continue to be exposed to the risks that are mitigated or eliminated by the Unwind. See responses to AG Items 1 and 43. The most immediate and reasonably predictable harm is the anticipated cessation of operation of one or both Smelters in the 2010-2012 time frame. The displacement of 1,400 jobs and the ripple effect of that economic development setback would be felt throughout Western Kentucky.

b. See the response to Item 26(a).
c. Big Rivers is unaware of the Smelters' position.
d. See E.ON's response.

Witness) a. Michael H. Core
b. Burns Mercer
c. Michael H. Core
d. E.ON U.S.

Item 27) Please reference the testimony of C. William Blackburn, page 9. It is stated that "Operating experience of the units as regulated assets can be developed during the initial period."

a. Specifically which operating experience of the units is unknown to BREC at this time; and

b. Specifically what operating experience of the units "as regulated assets" would be different than "an unregulated assets."

Response) a. Please see response to the Commission Staff's First Data Request, Item 22 (production cost model inputs).

b. The regulated production assets under Big Rivers' control may be operated differently than if they were unregulated assets. Some of the differences could be fuel mix, operating and maintenance objectives, generation levels, and economic dispatch criteria.

Witness) C. William Blackburn

Item 28) Please reference the testimony of C. William Blackburn, page 12, lines 8-16. To the extent not previously provided, provide documents showing the "increased purchase power payments from the Smelters".

a. Provide supporting documents showing the calculation details in determining such increased payments, including the prior amounts for three preceding years against which the increase is determined by comparison.

Response) The increased purchased power payments from the Smelters were in reference to the concurrent large industrial rate plus all of the additional payment required from the Smelters as well as payment in common with the non-Smelter Members. The statement was not in reference to prior period transactions.

Witness) C. William Blackburn

Item 29) Please reference the testimony of C. William Blackburn, page 20, lines 16-18. Reference is made here to a TIER level to provide "a reasonable opportunity to obtain and maintain an investment grade financial rating." Similarly, please state whether there is a leverage ratio metric (e.g., net debt/EBITDA) that is viewed as a threshold level for investment grade financial ratings. If so, please state that leverage ratio metric threshold. If not, please explain why not.

Response) The rating agencies do not have a stated minimum threshold leverage ratio to achieve an investment grade rating. An investment grade utility credit generally has a leverage ratio, as measured by total equity to total capitalization, in the range of 12-50%.

Witness) C. William Blackburn
Mark Glotfelty

Item 30) Please reference the testimony of C. William Blackburn, page 29, lines 10-13. Reference is made here to various types of data provided. To the extent not previously provided, please provide this same data, updated as appropriate, in electronic spreadsheet file format.

Response) Please see Big Rivers' response to the Commission Staff's Initial Data Request, Item 22.

Witness) C. William Blackburn

31

Item 31) Please reference the testimony of C. William Blackburn, page 71, line 8, regarding "implementation of the new Wholesale Smelter Agreements." To the extent not previously provided, provide a list stating and describing each and every material difference between the "old" smelter agreements, and the "new" smelter agreements.

Response) Big Rivers is unable to respond to the question because it is unclear what are the "old" smelter agreements. Please advise whether these agreements are (1) the 1998 agreements entered into among the smelters, predecessors of Kenergy and LG&E Energy Marketing, Inc., (2) the TIER 3 agreements among Big Rivers, Kenergy and the Smelters which currently are in effect but which will be terminated in connection with the Unwind, or (3) the pre-1998 agreements among Big Rivers, predecessors to Kenergy and the Smelters. All of these agreements are substantially different (in structure and otherwise) from the Smelter Agreements proposed to be entered into a connection with the Unwind. Consequently, Big Rivers requests additional guidance regarding the specific information in which the Attorney General is interested. Without this additional guidance, Big Rivers is concerned that it may not appropriately address areas of concern due to the inherent vagueness of subjectivity of a standard of materiality.

Witness) C. William Blackburn

32

Item 32) Please reference the testimony of C. William Blackburn, page 109, lines 16-17, at "the Unwind Transaction represents a negotiated transaction with an agreed-upon allocation of risks between Big Rivers, Big Rivers' members, the Smelters and the E.ON U.S. Parties."

a. Identify any other entities outside this negotiation group which bear risks from this transaction, but not included in the "negotiated transaction" (e.g., City of Henderson);

b. Identify and describe each "risk" that was considered and allocated; and,

c. Which party bears what share of "agreed-upon allocation" of each risk in b, above.

Response) a. There are no other entities whose risk factor changes due to the Unwind Transaction. With respect to the City of Henderson, their risks are the same with either plant operator. While E.ON U.S. could be perceived to be financially stronger, Big Rivers will certainly have financial viability that is far better than in the past and will be an investment grade rated organization. Certain of Big Rivers' creditors (i.e., the RUS) will have their risks diminished through the removal of their current subordinated position under Big Rivers' first mortgage.

b. Before entering into negotiations with either E.ON U. S. or the Smelters, Big Rivers identified the chief risks of an Unwind Transaction as generation operations, load concentration in serving the smelter load, fuel and financial risks. The Members are obviously exposed to all those risks. But within the Member load, the Smelters assume a disproportionate share of that risk exposure, while mitigating those risks to the Members so long as the Smelters are on the Big Rivers' system. The risk to Big Rivers and its Members of the Smelters leaving the Big Rivers system was mitigated, as stated in paragraph 53 of the Application. The Smelter Agreements also contain mechanisms that may allow the Smelters to survive business downturns or catastrophic circumstances, while preserving the anticipated economics for Big Rivers and its Members. Smelter witness Henry Fayne discusses these advantages at pages 10-11 of his pre-filed direct testimony.

c. See response to subpart b, above.

Witness) C. William Blackburn

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Item 33) Please reference the testimony of C. William Blackburn, page 124, lines 9-10, regarding "Big Rivers has not yet completed negotiations with its existing creditors concerning the provisions of the Indenture and the New Intercreditor Agreement". To the extent not previously provided, please provide copies of all correspondence between Big Rivers and its creditors since the point in time Big Rivers and E. ON decided to pursue the transaction.

Response) Big Rivers objects to this request on the ground that it seeks material pertaining to ongoing negotiations between Big Rivers and its creditors, which is privileged. Big Rivers additionally objects that materials relating to preliminary contracts or negotiations with its creditors are not relecvant to the financing arrangements that will be presented to the Commission, and therefore, the request is overly broad and premature.

Witness) C. William Blackburn
Counsel

Item 34) Please reference the testimony of C. William Blackburn, page 107, lines 8-9, regarding "investment grade ratings from Moody's and Standard and Poor's. Has Big Rivers sought indicative bond ratings from any rating entity such as Moody's or S&P? If so, please provide those indicative bond rating documents.

Response) No, Big Rivers has not requested an indicative bond rating at this time.

Witness) C. William Blackburn

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Item 35) Please reference the testimony of C. William Blackburn, page 11, lines 8-9, regarding "the Unwind Transaction contemplates system expansion...." Provide documents which show and describe Big Rivers' contemplated system expansion under the Unwind Transaction, and subsequent to it.

Response) The Unwind Transaction will allow Big Rivers the financial ability to look at additional power supply options for economic development that were previously not available. Big Rivers may look at adding combustion turbines, combine cycle turbines, long-term purchased power agreements, purchasing a portion of a new coal fired unit, or a combination of the above.

Big Rivers did not want to further complicate the Unwind Transaction with any type of system expansion. Therefore any studies for system expansion have not been developed at this time.

As economic development opportunities become available, Big Rivers will have the flexibility to provide additional sources of reliable power to its Member Distribution Systems.

Witness) C. William Blackburn

Item 36) Please reference the testimony of C. William Blackburn, page 13, lines 6-9, "improved financial arrangements will in turn make Big Rivers much more able to respond to changing market circumstances...".

a. Please specifically identify the "changing market circumstances."

b. Assume the Lease Agreement and Purchase Power Agreement is not terminated. Please specifically identify any "changing market circumstances" that Big Rivers would not be able to respond to under its current financial structure.

Response) a. Changing market circumstances can mean many different things, such as financial markets, operational conditions, economic development supply needs, capital improvements, etc.

Big Rivers will have the ability to obtain secured financing when necessary, or preferable, for major capital improvements. The lines of credit Big Rivers will have available will enable it to meet unanticipated short-term cash flow requirements for operations, inventories, etc.

b. All the above would be impracticable, if not impossible, to accomplish under the current Lease and Purchase Power Agreements.

Witness) C. William Blackburn

Item 37) Please reference the testimony of C. William Blackburn, page 19, lines 5-7, consent fees, "discussions with those creditors remain ongoing." Provide all documents to and from Big Rivers' creditors regarding consent fees, restructure of debt to accomplish and support the Unwind Transaction, etc.

Response) Big Rivers objects to this request on the grounds that it seeks material pertaining to ongoing negotiations between Big Rivers and its creditors, which is privileged. Big Rivers additionally objects that materials relating to preliminary negotiations are not relevant to the financing arrangements that will be presented to the Commission, and therefore, the request is overly broad and premature.

Witness) C. William Blackburn
Counsel

Item 38) Please reference the testimony of C. William Blackburn, page 27, line 18 to Page 28, line 10, regarding inputs to the production cost model. For each of the enumerated inputs 1-9, provide documents which show sensitivity analyses addressing the sensitivity of production cost model outputs to changed inputs.

Response) Please refer to Big Rivers' response to the Commission Staff's Initial Request for Information , Item 9c.

Witness) C. William Blackburn
Robert S. Mudge

Item 39) Please reference the testimony of C. William Blackburn, page 28, line 11 to Page 29, line 15, regarding inputs to the financial model provided by Big Rivers. Provide the documents (whether paper or electronic, and if electronic in native electronic format – not. pdf) which contain or support the "numerous inputs" referenced here.

Response) Please see Big Rivers' response to the Commission Staff's Initial Request for Information, Item 22.

Witness) C. William Blackburn
Robert S. Mudge

Item 40) Please reference the testimony of C. William Blackburn, page 34, line 22 to Page 35, line 2, regarding the Hill & Associated review.

a. Please provide the most recent Hill & Associates review document in its entirety;

b. Provide the updated review document as referenced here.

Response) a. and b. Attached are the most recent and updated review documents.

Witness) C. William Blackburn

[REDACTED]

Item 41) Please reference the testimony of C. William Blackburn, page 124, line 21 to Page 125, line 3, regarding "Big Rivers anticipates [beginning the process of obtaining investment grade credit ratings] will occur in the very near term..." Provide specific dates as to when "the very near term" is anticipated to occur.

Response) Big Rivers has scheduled meetings with Standard & Poors and Moody's on March 5, 2008.

Witness) C. William Blackburn

Item 42) Please reference the testimony of C. William Blackburn, page 128, lines 1-3 reference "assumed" interest rates. Provide current market interest rates (on a comparable basis) for the same profile of debt obligation as assumed here.

Response) See response to Attorney General's Initial Request, Item 23.

Witness) C. William Blackburn
Mark Glotfelty

Item 43) Please reference the testimony of C. William Blackburn, page 77, lines 7-10, "one consequence of Big Rivers resuming control over its formerly leased generation assets is that future power supply costs may increase now that a significant portion of Big Rivers' costs are no longer largely fixed under the Lease Agreement." Explain why it is in the public interest to expose Big Rivers and its member cooperatives to increased power supply costs when such costs currently are largely fixed under the Lease Agreement.

Response) Although future power supply costs *may* increase, the Unwind Transaction is consistent with the public interest for many reasons. First, Member rates are not increased initially, and Members are shielded from increases in environmental surcharge and fuel adjustment clause costs for approximately five years. Second, even though power costs are largely fixed under the Lease Agreement, there is no flexibility for load growth or any guarantee of a long-term availability of power for Members at the end of the Lease. Third, in addition to added financial flexibility for the future, Big Rivers will receive large immediate and tangible benefits under the Unwind Transaction—to the tune of approximately $623 million from E.ON alone and approximately $327 million in contributions from the Smelters. Big Rivers has made a considered business judgment that, balancing the Unwind Transaction against the current arrangement, the Unwind Transaction is more in the public interest—and in its Members' interests—than the existing Lease Agreement. The factors taken into consideration by Big Rivers in developing the Unwind Transaction are discussed further, below.

Financing Limitations

Under the Lease Agreement, Big Rivers is unable to finance significant new capital additions. The arrangement between Big Rivers' creditors is complex and complicated by RUS's subordinate position to the other creditors. Trying to finance any new capital needs in the remaining 16 years of the First Mortgage would be extremely difficult. Attempting to bring together the creditors involved in the First Mortgage with varying interests in Big Rivers has already proven very difficult. An Unwind would put in place an indenture that greatly simplifies financing going forward.

A $15 million line of credit currently exists with CFC, and it must be paid down to a zero balance at least once a year. However, in the world of power supply, $15 million is a drop in the bucket when it comes to capital expenditures. Thus, sudden large cash needs present significant problems, including the potential of being in default under the Lease Agreement, or worse, bankruptcy. Here are some examples of possible issues that could cause the need for more funds:

1. Major Capital Expenditures as defined in the Lease Agreement.
2. Large claims awarded under litigation with either the Smelters or E.ON or both.
3. Unknown new incremental environmental costs as defined in the Lease Agreement.
4. New Source Review claims from EPA.

Being unable to adequately finance capital expenses puts more risk on Big Rivers' Members in that today's Members bear all of the responsibility for raising capital that cannot be provided by internal funds. There is little flexibility for management when it comes to raising capital in dealing with such needed capital additions, litigation liability, or environmental assessments.

Moreover, dealing with an issue such as higher than expected load growth would also be difficult since Big Rivers would be unable to borrow funds to purchase more generating assets. Further, Big Rivers' weak balance sheet makes it difficult to partner with others on power supply options or other opportunities to reduce costs through better economies of scale. The use of long term power purchase contracts would be problematic because Big Rivers' weak balance sheet would prompt sellers of wholesale power to keep credit exposures much shorter in duration or require security, which Big Rivers cannot adequately provide.

In addition, without an indenture in place at the end of the Lease Agreement in 2023, financing the Asset Residual Value Payment (ARVP) due to the RUS of approximately $250 million will be complex, if not impossible. Under the existing First Mortgage both Philip Morris Capital Corp. (PMCC) and Bank of America through the arrangements of the sale leaseback, are mortgagees under the First Mortgage, and have some control over Big Rivers' financing through the First Mortgage. Getting their permission for modification of the mortgage could result in a demand for a payment or create a demand of a buyout of a Lease Agreement, a very expensive proposition for Big Rivers. The ARVP Note to the RUS is due December 31, 2023. Negotiations, documentation and closing of the financing of the ARVP Note would likely require at least a year to complete. Also, at the end of the existing transaction Big Rivers is required to pay E.ON for its inventory on hand which could cost an additional $50-60 million, and which would also need to be financed.

The Residual Value Payment (RVP) owed to E.ON increases the need for cash and thus creates a need for higher rates or more financing at the conclusion of the existing transaction if cash is not available for the payment. Since this amount is due 180 days after the termination of the existing transaction, negotiations, documentation and closing the financing for it would require starting at least one year ahead of the termination date. In January 2024, the likelihood also exists that Big Rivers could find itself without sufficient cash to pay for additional capital needs at the existing power plants and/or perhaps new capacity to meet member growth. This could exacerbate financing problems at the time. In other words, the complexity of these issues will present significant challenges to Big Rivers in the early 2020s. Big Rivers believes there will not be a better opportunity to eliminate most of those potential risks than by embracing the flexibility of the Unwind Transaction.

16 Years of Adversarial Relationships

It is readily apparent that if an Unwind is not achieved, the last 15 years of the Lease Agreement will likely be a period of adversarial relationships. First, the relationship with E.ON will likely involve many disagreements, disputes and possible litigation over numerous contract issues. Current unresolved issues with E.ON already exist. These issues have been left on the table and would go away with a closing of the Unwind. If there is no closing, those disputes will come front and center.

The complex agreements between Big Rivers and the E.ON entities invite disputes. It is never easy or inexpensive to be in a contractual relationship with a party who wants to exit the relationship. E.ON's position in this regard is well-documented.

In addition, if Big Rivers remains under the Lease Agreement, the Smelters will be desperate to find a source of power priced at a level that will sustain them for a period beyond the expiration of their respective power supply contracts in 2010 and 2011. To the extent that Big Rivers agrees to supply some power for resale to the Smelters in the interest of making that very limited contribution to extending their viability, Big Rivers' ability to arbitrage will be adversely affected. If the Smelters attempt to force power supply concessions from Big Rivers and are successful, Big Rivers could also be at risk of having to take all new load growth to the market and socialize the costs over all Members.

Economic Development for Western Kentucky

Only the Unwind can provide the Smelters the power they need to continue cost-effective aluminum production beyond 2010 and 2011. Economic stability and development have always been a major focus of Big Rivers and its Members. The Unwind, in addition to retaining the 1,400 direct Smelter jobs and the hundreds of indirect jobs attributable to the Smelters, will provide the flexibility for Big Rivers to promote other economic development in the region. Being financially strong will allow Big Rivers to explore different avenues and employ greater resources in meeting load growth.

The Shorter Term View for Power Supply

From Big Rivers' perspective, the Lease Agreement provides only a short term view of power supply for the Members and Big Rivers. While there are over 15 years left in the Lease Agreement, that is not a very long term view of power supply when viewed from the perspective of the all requirements contracts Big Rivers has with its Members. Acquiring new power resources can require a decade or more to study options, to develop an integrated resource plan, to get necessary permits if new assets are to be constructed, to negotiate sharing agreements if they are to be employed, and finally to construct, or put into place, power supply resources for the future.

If Big Rivers' load service obligations grow faster than its projections, other than short term market purchases, few options exist under the Lease Agreement to meet that growth. Such a load service squeeze will likely result in significantly higher costs to Members and have a chilling effect on economic development for the next 15+ years if the Lease Agreement remains in effect.

Witness) Michael H. Core

Item 44) Please reference the testimony of C. William Blackburn, page 86, line 12, regarding "sensitivity run."

a. Identify all "sensitivity runs" performed by or for Big Rivers in support of its conclusion to terminate the Lease Agreement and propose the Unwind Transaction.

b. Provide an electronic copy (.xls file in machine readable format with formulas intact) of each such sensitivity run, above.

Response) Big Rivers objects to this request to the extent it seeks any sensitivities run on preliminary versions of the Unwind Financial Model not filed with the Commission on the grounds that those sensitivity runs are irrelevant to the proposal before the Commission and are privileged as being related to negotiations with the parties, and that providing them would be unduly burdensome. Without waiving that objection, included each sensitivity run performed by or for Big Rivers in connection with the final version of the Unwind Financial Model filed with the Commission.

a.-b. The sensitivity analyses referred to in the testimony of C. William Blackburn on page 86 have examined scenarios in which one or both Smelters terminated their contracts per the terms of their agreements. (Section 7.3 of the retail agreements). Sensitivity analyses have been prepared.

Scenario One: Century terminates at EOY 2010.

Scenario Two: Century terminates at EOY 2010 and Alcan terminates at EOY 2011.

Full model runs are attached at PSC Item 10 and PSC Item 12(b). See also AG Items 23 and 133.

Witness) C. William Blackburn
Robert S. Mudge

Item 45) Please reference the testimony of C. William Blackburn, page 91, lines 6-7, regarding "certain provisions providing for a sharing of the costs of certain large fuel increases..." Specify each such provision referred to here.

Response) The current Power Purchase Agreement with LEM in Section 6.3, Base Power Rate, subsection b, provides for the base power rate to be adjusted on the formula contained therein. For your convenience a copy of Section 6.3 b is attached.

Witness) C. William Blackburn

(b) An amount equal to Big Rivers' total revenues actually collected for Hoosier Power sold to Hoosier by Big Rivers during the prior month.

(c) An amount equal to Big Rivers' total revenues actually collected for HMP&L Power sold to HMP&L by Big Rivers during the prior month.

(d) An amount equal to the Base Power Price for such month as determined pursuant to Section 6.4.

(e) An amount equal to the redispatch costs incurred by Big Rivers pursuant to Section 5.4 during the prior month.

(f) An amount based upon the quantity of generation-based Ancillary Services, ECAR reserves or Transmission Support Services provided by LEM to Big Rivers during the prior month in excess of the type and quantity of such services which are explicitly to be provided pursuant to this Agreement without adjustment to the Power Value Amount, priced in accordance with LEM's rates for such services.

(g) To the extent that Big Rivers purchases from a third-party ECAR automatic reserves or generation-based emergency services necessary to support operation of its Transmission System, the Power Value Amount shall be reduced by an amount equal to Big Rivers' actual cost of such purchases during the prior month; provided that ECAR automatic reserves or generation-based emergency services shall not be purchased in amounts greater than the minimum amount required under ECAR regulations.

6.3 Base Power Rates.

(a) Base Power. During the first Partial Year through December 31, 2001, the rate per megawatt-hour of Base Power is $18.917. For the balance of the Term of this Agreement, the following rates per megawatt-hour for Base Power apply:

2002	$19.117
2003	$19.217
2004	$19.317
2005	$19.417
2006	$19.517
2007	$19.717
2008	$20.017
2009	$20.327
2010	$20.627
2011	$20.947
2012	$20.267
2013	$20.587

2014	\$20.917
2015	\$21.247
2016	\$21.587
2017	\$21.927
2018	\$22.277
2019	\$22.627
2020	\$22.987
2021	\$23.357
2022	\$23.717
2023	\$24.082
2024	\$24.452

(b) Base Power Rate Adjustments. Prior to February 1 of the Years 2004, 2011 and 2018, the Parties shall perform the following calculations:

Let P*n* represent the rate for Base Power for year *n* as defined in Section 6.3(a).

Define Q*n* = 9.52x + 7.25y + 3.23 where, for each year *n* of 2004, 2011, and 2018:

x = The ratio of the value of the Coal Index (DRI Price of Coal to Electric Utilities - National) at January 1 of year *n* to the value at January 1 of the seventh preceding year; and

y = The ratio of the value of the Labor Index (DRI Unit Labor Cost - National) at January 1 of year *n* to the value at January 1 of the seventh preceding year.

(i) 2004 Adjustment

(A) If Q2004 is less than 16.69, then set F2004 = Q2004 ÷ 16.69

(B) If Q2004 is greater than 35.32, then set F2004 = Q2004 ÷ 35.32

(C) If neither determination (1) or (2) is made, then set F2004 = 1.0.

(D) The adjusted rate for Base Power, P'*n* for each year *n* from 2004 through 2010 shall be determined as P'n = Pn • F2004

(ii) 2011 Adjustment

(A) If Q2011 is less than 20.66 • F2004, then set F2011 = Q2011 ÷ 20.66

(B) If Q2011 is greater than 43.73 • F2004, then set F2011 = Q2011 ÷ 43.73

(C) If neither determination (1) or (2) is made, then set F2011 = F2004

(D) The adjusted rate for Base Power, P'*n* for each year *n* from 2011 through 2017 shall be determined as P'n = Pn • F2011

(iii) 2018 Adjustment

(A) If Q2018 is less than 25.59 • F2004 • F2011, then set F2018 = Q2018 ÷ 25.59

(B) If Q2018 is greater than 54.15 • F2004 • F2011, then set F2018 = Q2018 ÷ 54.15

(C) If neither determination (1) or (2) is made, then set F2018 = F2004 • F2011

(D) The adjusted rate for Base Power, P'*n*, for each year *n from 2018 through the Term of* this Agreement shall be determined as P'n = Pn • F2018

(iv) Base Power rate adjustments will be effective on January 1 of the Year the calculation is performed.

(c) In the event that the Effective Date does not occur on or before December 31, 1998 then Section 6.3(a) will be modified, effective January 1, 1999, and on each January 1 thereafter until the Effective Date occurs (after which time the Section will remain fixed in the form then current), subject to an earlier termination of the Participation Agreement, *as follows:* each Year *stated will be* increased by one, such that the rate in the first Partial Year that the Agreement is in effect and through the three calendar years immediately following the first Partial Year will be $18.917 and the remainder of the rates will become effective in the corresponding Year indicated after such modification is made.

Item 46) Please reference the testimony of C. William Blackburn, page 21, lines 9-16: identify each difference in calculation of "TIER" as used or likely to be used by:

a. Creditors in credit agreements;
b. Credit rating entities; and
c. Smelters via the "Smelter Agreements."

Response) Please see response to Commission Staff's Initial Data Request, Item 13. The creditors and credit rating entities will likely use the conventional TIER calculation.

Witness) C. William Blackburn

Item 47) Please reference the testimony of Robert S. Mudge, page 5, line 10-11, "at the outset of negotiations relating to the Unwind Transaction in 2003." State each material factor that was an impetus to opening these negotiations.

Response) When the concept of the Unwind was put to Big Rivers, Big Rivers recognized the potential for the benefits to Big Rivers, its Members and Western Kentucky described in the responses to AG questions 1 and 43. We believe Big Rivers was compelled to enter into negotiations to determine whether those benefits were achievable, and to give Big Rivers Board of Directors and its Members the opportunity to consider the best available transaction.

Witness) Michael H. Core

Item 48) Please reference the testimony of Robert S. Mudge, page 10, line 3, "financing has been modeled to minimize costs." State specifically how the financing as modeled "minimizes costs."

Response) The reference to *minimizing costs* relates to the structuring of potential financing such that the most expensive debt components are repaid early, and the less expensive components are kept in place as long as possible, within the constraints of maturities imposed by contract or tax regulations and other objectives such as reducing RUS exposure. For example, the financing plan embedded in the Financial Model models the extension of maturity dates currently applicable to Big Rivers' tax-exempt pollution control bonds, which can reasonably be expected to represent Big Rivers' cheapest capital going forward.

Witness) Robert S. Mudge

Item 49) Please reference the testimony of Robert S. Mudge, page 17, lines 1-7, regarding capital expenditures. Provide any sensitivity analysis scenarios conducted regarding variation of "capital expenditure assumptions" from that assumed and presented in the Unwind Financial Model (Exhibit 8). Provide these scenarios in electronic spreadsheet file format, along with any description of the sensitivity analysis scenario.

Response) Although we employed different capital expenditures in negotiating the transaction and in designing the Financial Model, formal sensitivity analyses were not considered meaningful in light of the complexity in balancing the transactional costs and benefits. To my knowledge, the engineers and operations people at Big Rivers were comfortable with the range of capex used throughout the Financial Model. See Mudge Testimony, Exhibit 9, page 17.

Witness) Robert S. Mudge

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 50) Please reference the testimony of Robert S. Mudge. Provide any documents prepared for or provided to Applicants by him or his firm pertaining to matters within this application since being retained in 2003.

Response) Big Rivers objects to this request on the ground that it seeks material that is protected by the attorney-client and work product privileges. CRA International was retained by Big Rivers' counsel. Big Rivers further objects on the grounds that the request seeks privileged communications pertaining to negotiations, and that it is overly broad, unduly burdensome, and irrelevant.

Witness) Robert S. Mudge
Counsel

Item 51) Please reference the testimony of Robert S. Mudge. Provide any documents in his possession regarding the future costs of complying with environmental regulations related to coal fired plants and their operation.

Response) Big Rivers objects to this request to the extent it seeks material not directly related to Big Rivers, on the grounds that it is overly broad, it is unduly burdensome, it seeks proprietary information prepared for other clients of CRA International, and it is irrelevant. Without waiving this objection, see the attachments to AG Initial Request Item 133, and PSC Initial Request Item 22.

Witness) Robert S. Mudge

Item 52) Please reference the testimony of Mark W. Glotfelty, pages 8-9, regarding "credit strengths the ratings agencies will consider." Identify and discuss any other credit strengths the ratings agencies will consider, beyond those listed here.

Response) Other credit strengths the rating agencies consider is the experience, depth and strength of the executive management team. Primary focus will be on management's business strategy and ability to successfully manage the company. One area the rating agencies focus on is management's track record in meeting or exceeding financial projections.

Witness) Mark W. Glotfelty

Item 53) Please reference the testimony of Mark W. Glotfelty, pages 9, regarding "credit concerns the ratings agencies will likely focus upon." Identify and discuss any other credit concerns the ratings agencies will consider, beyond those listed here.

Response) The listed credit concerns in the testimony are the key areas the rating agencies are likely to focus upon.

Witness) Mark W. Glotfelty

Item 54) Please reference the testimony of Mark W. Glotfelty. Provide any reports prepared for, provided to, or otherwise created for this matter for the Applicants by him/Goldman Sachs.

Response) There are no reports prepared for or provided to myself as part of my testimony. My testimony is based on my knowledge of the credit rating process from my time spent as a credit analyst.

Witness) Mark W. Glotfelty

Item 55) Please reference the testimony of Mark W. Glotfelty. Provide any documents in his possession regarding the future costs of complying with environmental regulations related to coal fired plants and their operation.

Response) I was not provided any documents on the future cost of complying with environmental regulations related to coal fired plants. My testimony is based on my knowledge of the rating agencies focus on the potential liability.

Witness) Mark W. Glotfelty

Item 56) Please reference the testimony of Mark W. Glotfelty, page 11. Provide the entire document from which the table on this page was drawn.

Response) Please see the attached June 2007 G&T Accounting & Finance Association annual directory.

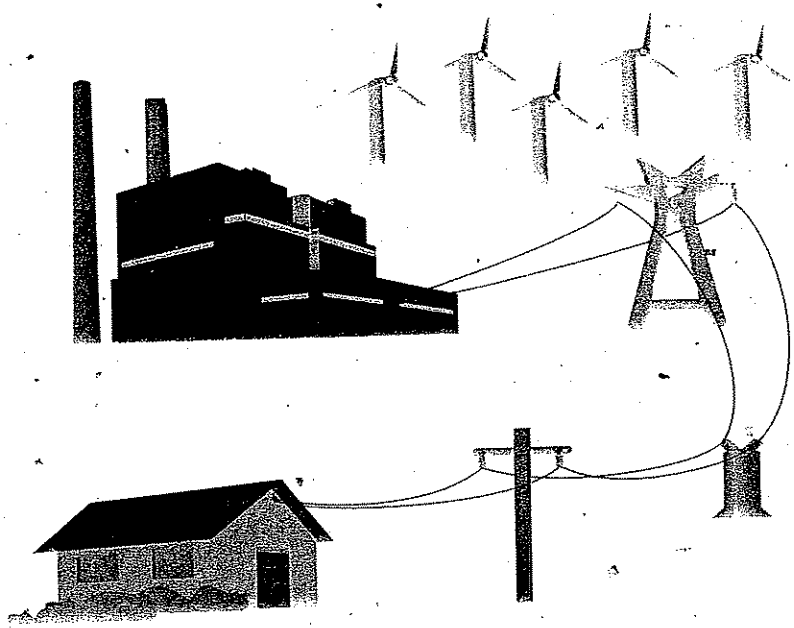
Witness) Mark W. Glotfelty

G & T Phone Numbers

Alabama	(334) 427-3000
Allegheny	(717) 233-5704
Arizona	(520) 586-3631
Arkansas	(501) 570-2200
Associated	(417) 881-1204
Basin	(701) 223-0441
Big Rivers	(270) 827-2561
Brazos	(254) 750-6500
Buckeye	(614) 846-5757
Central Electric-MO	(573) 634-2454
Central Electric-SC	(803) 779-4975
Central Iowa	(319) 366-8011
Central Montana	(406) 268-1211
Central Power-ND	(701) 852-4407
Chugach	(907) 563-7494
Corn Belt	(515) 332-2571
Dairyland	(608) 788-4000
Deseret	(801) 619-6500
East Kentucky	(859) 744-4812
East River	(605) 256-4536
Georgia Transmission	(770) 270-7400
Golden Spread	(806) 379-7766
Great River	(763) 441-3121
Hoosier	(812) 876-2021
KAMO	(918) 256-5551
Kansas	(785) 273-7010
M & A Electric	(573) 785-9651
Minnkota	(701) 795-4000
N.W. Electric	(816) 632-2121
Nebraska	(402) 564-8142
New Horizon	(864) 682-3159
North Carolina	(919) 872-0800
Northeast Missouri	(573) 769-2107
Northeast Texas	(903) 757-3282
Northwest Iowa	(712) 546-4141
Oglethorpe	(770) 270-7600
Old Dominion	(804) 747-0592
PNGC Power	(503) 288-1234
Power Resources	(503) 288-1234
Rayburn Country	(972) 771-1336
Rushmore	(605) 342-4759
Saluda River	(864) 682-3169
Sam Rayburn	(936) 560-9532
San Miguel	(830) 784-3411
Seminole	(813) 963-0994
Sho-Me Power	(417) 468-2615
Sierra Southwest	(520) 586-5000
South Mississippi	(601) 268-2083
South Texas	(361) 575-6491
Southern Illinois	(618) 964-1448
Southwest	(520) 586-5599
Soyland	(217) 245-6161
Square Butte	(701) 795-4000
Sunflower	(785) 628-2845
Tex-La	(936) 560-9532
Tri-State	(303) 452-6111
Upper Missouri	(406) 433-4100
Wabash Valley	(317) 481-2800
Western Farmers	(405) 247-3351
Western Montana	(406) 721-0945
Wolverine	(231) 775-5700

G&T Accounting & Finance Association

Annual Directory June 2007



Disclaimer

The G&T Accounting and Finance Association (Association) provides this directory as an information source for employees of the Electric Generation and Transmission Electric Cooperatives (G&Ts) of the United States, the National Rural Electric Cooperative Association, the Rural Utilities Service, the National Rural Utilities Cooperative Finance Corporation, and CoBank.

The directory reflects information provided by each G&T. The Association made no attempt to audit or verify the data submitted. Caution should be used in making statistical comparisons between two or more G&Ts due to significant diversity in the organizational, operating, and capital structures of many G&Ts. Questions regarding information should be directed to the G&T in question.

G&T Accounting and Finance Association Members

G&T Rankings

Other

Alabama Electric Cooperative, Inc.

2027 East Three Notch St.
P.O. Box 550
Andalusia, AL 36420

Main Telephone (334) 427-3000
Main FAX (334) 427-3401
www.powersouth.com

Executive Contacts

President & Chief Executive Officer .... *Gary Smith*
Executive Secretary .... *Teresa Nelson*
Vice President & CFO Financial Services .... *F. Ferrell Walton*
Vice President, Power Production .... *Damon Morgan*
Vice President, Operations & Engineering .... *Larry Avery*
Vice President, Bulk Power & Delivery .... *Ken Skroback*
Vice President, Legal Affairs .... *Beth Woodard*
Vice President, Government and Economic Affairs .... *Horace Horn*

Accounting & Finance Related Personnel

Finance & Accounting .... *Jacob N. Jones - Accounting & Finance Manager*
Property Accounting .... *Jacob N. Jones*
Insurance—Plant .... *Robert A. Kyle - Financial Planning Manager*
Resource Planning .... *David Tarpley - Bulk Services Manager*

Ultimate Meters Served	399,800	Taxable	No
REC Members	16	State Regulated	No
Other Firm Power Customers	4	Year Organized	1941
Power Pool	No	CPA - Tax	Deloitte & Touche LLP
Total Plant Capacity	1,724 MW	CPA - Audit	Deloitte & Touche LLP
# of Substations	284	**Corporate Insurance Providers**	
Miles of Transmission Line	2,213	Worker's Comp.	Wausau
Total Employees	542	Primary Liability	Self Insured
Union Employees	211	Commercial Umbrella	AEGIS & EMI
RUS Designation	AL 42	Electric Property	Factory Mutual

2006 Financial Keys

Total Assets	$1,199,633,625
Total Operating Revenue	$617,660,934
Net Margins	$14,205,315
Equity Ratio	9.28%
T.I.E.R.	1.29
Cost of Debt	5.72%
DSC Ratio	1.17
MFIR	1.29

MW Peak Demands

Winter	1,937
Summer	1,846

2006 MWH Sales

Member	8,590,026 @ $64.98 per MWH
Non-Mem	908,385 @ $63.13 per MWH

Alabama Electric Cooperative, Inc.

ORGANIZATION

Alabama Electric Cooperative, Inc. (AEC), is an Alabama non-profit electric generation and transmission cooperative formed in 1941. AEC provides wholesale electric service to its 20 members which consist of 16 rural electric distribution systems, 4 municipalities as of December 31, 2006.

MEMBERSHIP

AEC's Board of Trustees consists of two representatives from each of the members. The consumers served by the 20 members serve predominately rural areas of central and south Alabama and northwest Florida.

POWER SUPPLY

In 2006, AEC generated 5,929,124 MWH of power and purchased 3,876,372 MWH from other power generators. AEC's energy was primarily produced by the Lowman Power Plant located in west Alabama, Vann Combined Cycle Plant located in Gantt, Alabama and Miller Power Plant located in Jefferson County, Alabama

FINANCIAL/RATES

AEC is a *non-profit cooperative, with* 3 small taxable cooperations which are subject to federal taxes. AEC nor any of its member systems are subject to state regulation.

AEC, per Indenture dated January 1, 2000 must maintain a margin for interest ratio (MFIR) of 1.065. AEC again in 2006 as in 2004 & 2005 obtained a BBB+ (stable) credit rating from S & P.

TRANSMISSION

AEC owns a 2,213 mile network of transmission lines consisting of 183 miles of 230 kv lines, 1,349 miles of 115 kv lines, 681 miles of 46 kv lines and most of the related substations.

OTHER POINTS OF INTEREST

Alabama Electric Cooperative, Inc. (AEC) wholesale power rates to its member systems continue to be very competitive with the surrounding utilities.

AEC is committed in its efforts to provide services for their member systems. To this end AEC owns a small propane gas company, a short line railroad and a subsidiary to promote economic development. AEC is in a position to continue to improve services in these areas to meet the needs of its member systems as required.

AEC began working in 2005 on an extensive *air quality control project (AQC)* at it's coal fired Lowman Power Plant. This project is estimated at approximately $250 Million. The first phase of this project will be completed in 2007 with the second phase to be complete in 2008.

212 Locust Street
P.O. Box 1266
Harrisburg, PA 17108

Main Telephone (717) 233-5704
Main FAX (717) 234-1309
www.ccsenergy.com

Executive Contacts

President & CEO	*Frank M. Betley*
Vice President Power Supply & Engineering	*Richard W. Osborne*
Vice President Finance & Accounting	*Kenneth W. Kammeier*
Vice President Strategic & Corporate Services	*Laurence V. Bladen*

Accounting & Finance Related Personnel

Finance	
Treasury	*Kenneth W. Kammeier*
General Accounting	*Ingrid S. Benny*
Property Accounting	*Edward L. Stevens*
Tax Accounting	*Tania Werry*
Internal Auditing	*Kent R. Springman*
Resource Planning	*Kent R. Springman*
	Edward L. Stevens

Ultimate Meters Served	223,000
REC Members	14
Other Firm Power Customers	0
Power Pool	PJM
Total Plant Capacity	256 MW
# of Substations	4
Miles of Transmission Line	82
Total Employees	55
Union Employees	0
RUS Designation	PA27

Taxable	Yes
State Regulated	No
Year Organized	1946
CPA - Tax	Deloitte & Touche, LLC
CPA - Audit	BKD, LLP
Corporate Insurance Providers	
Worker's Comp.	Rochdale Services
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Chubb

2006 Financial Keys

Total Assets	$360,495,996
Total Operating Revenue	$180,062,423
Net Margins	$26,286,249
Equity Ratio	11.50%
T.I.E.R.	3.80
DSC Ratio	1.51
Cost of Debt	6.90%

MW Peak Demands

Winter	631
Summer	602

2006 MWH Sales

Member.....2,833,858 @ $56.90 per MWH
Non-Member 118,340 @ $13.00 per MWH

ORGANIZATION

Incorporated on July 9, 1946, Allegheny Electric Cooperative, Inc. is exempt from regulation by the Pennsylvania Public Utility Commission.

MEMBERSHIP

Allegheny's Board of Directors consists of one director elected from each of its 13 member electric cooperatives in Pennsylvania and one in New Jersey. Allegheny's member cooperatives own and maintain about 12.5 percent of the electric distribution lines in Pennsylvania, covering nearly one-third of the state's land area in 41 counties, serving more than 600,000 rural residents.

POWER SUPPLY

The bulk of Allegheny's power supply comes from its 10 percent ownership in the Susquehanna Steam Electric Station (SSES), a 2,355-megawatt, two-unit nuclear power plant located near Berwick, PA. In 2006, the facility supplied 60.4 percent of Allegheny's power supply needs. In 1988, the cooperative's first wholly operated generating plant, the Raystown Hydroelectric Project, William F. Matson Generating Station, was declared in commercial operation. During an average year, it supplies 4 percent of the energy delivered by Allegheny, enough for about 8,500 average rural homes. As a preference customer, Allegheny also purchases hydropower generated by the publicly owned Niagara Power Project operated by the New York Power Authority. Allegheny has also entered into a purchased power agreement with Williams Energy Marketing and Trading that runs through 2008.

ALL-REQUIREMENTS CONTRACT & TERRITORIAL INTEGRITY

Allegheny's member cooperatives have entered into wholesale power and power cost pooling contracts to purchase all their power supply needs from Allegheny and adjust their rates to insure the cooperative's solvency. These contracts run through December 31, 2025. The Unincorporated Area Certified Territory Law, signed into law in July 1975, and recodified in 1990, assigns exclusive territories for all of Pennsylvania's rural electric cooperatives and private power companies.

DEREGULATION

In 1996, Pennsylvania enacted the Electricity Generation Customer Choice and Competition Act. Full customer choice became in effect statewide January 1, 1999.

FINANCING

In March 2006, Allegheny bought out of Rural Utilities Service (RUS) with nearly $300,000,000 of financing provided by National Rural Utilities Cooperative Finance Corporation (CFC). The financing provided by CFC included a short-term loan, long-term loans, loans for future capital additions, a line of credit, and letters of credit. This financing provides for all of Allegheny's debt and credit support needs for the foreseeable future.

Arizona Electric Power Cooperative, Inc.

P.O. Box 670
Benson, AZ 85602

Main Telephone (520) 586-3631
Main FAX (520) 586-5343
www.aepnet.com

Executive Contacts

Chief Executive Office	*Donald W. Kimball**
Executive Assistant	*Valerie Nicholson**
Chief Financial Officer	*Dirk C. Minson**
Chief Operating Officer-Sierra	*Robert A. Hewlett*
Chief Operating Officer-SWTC	*Larry D. Huff***
Chief Operating Officer-AEPCO	*Gary Grim*

**Employed by Sierra Southwest*
***Employed by Southwest Transmission*

Accounting & Finance Related Personnel

Finance	*Dirk C. Minson**
Treasury	*Gary E. Pierson - Financial Services Manager**
Property Accounting	*Nadine Azzopardi**
Tax Accounting	*Richard Franklin**
Internal Auditing	*James Felch - Internal Auditor**
Insurance - Plant	*Patrick Ledger**
Data Processing	*Lee Wilfert, CIO**
Employee Benefits	*Emery Silvester - Human Resource Manager**
Resource Planning	*Cliff Cathers**
Manager of Accounting	*Valerie Hoyt**

Ultimate Meters Served	200,000
REC Members	6
Other Firm Power Customers	6
Power Pool	N/A
Total Plant Capacity	597 MW
# of Substations	N/A
Miles of Transmission Line	N/A
Total Employees	19
Union Employees	0
RUS Designation	AZ 28

Taxable	Yes
State Regulated	Yes
Year Organized	1961
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Moss Adams LLP

Corporate Insurance Providers

Worker's Comp.	Arizona State Fund
Primary Liability	Federated
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$279,561,295
Total Operating Revenue	N/A
Net Margins	N/A
Equity Ratio	N/A
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	5.97%

MW Peak Demands
Member Only

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	3,336,119
Non-Mem	154,656

Arizona Electric Power Cooperative, Inc.

ORGANIZATION

Arizona Electric Power Cooperative, Inc. (AEPCO) was incorporated in 1961 as an electric generation and transmission cooperative. AEPCO provides wholesale electric service to its 6 Class A members, all of which are rural electric distribution cooperatives (the "Distribution Cooperatives"). Four of the six Distribution Cooperatives serve a major portion of the rural areas of the southeast section of Arizona with one of these Distribution Cooperatives *serving* portions of two counties in New Mexico. Another Distribution Cooperative *serves* the *northwest* corner of Arizona and the remaining Distribution cooperative serves rural areas in Southern California. AEPCO also supplies partial requirements power to one Class B and one Class C member. The Class B member is the City of Mesa, Arizona, a suburb of Phoenix, Arizona, and the Class C member is Salt River Project, an Arizona public power authority. AEPCO, which is located in Benson, Arizona, is a not-for-profit cooperative corporation which began *commercial operation in 1962.*

MEMBERSHIP

AEPCO's *Board of Directors* is composed of 2 directors from each of the 6 distribution cooperatives as well *as an additional Director* from each of the Class B and C members for a total of 14 directors. Each Class A member director must be a director or a manager of the distribution cooperative which he or she represents. The Board of Directors normally meets once each month and is responsible for setting corporate policy and approving rate and financing applications submitted to the State Regulator.

POWER SUPPLY

AEPCO owns and operates Apache Generating Station near Cochise, Arizona. Apache's 7 generating units have a combined capacity of 597 MW. Twin 195 MW units constitute AEPCO's baseload resource. While these units burn coal as their primary fuel, both units also have the capacity to burn natural gas as their primary fuel. The *remaining* 207 *MW* is composed of four gas turbines totaling 133 MW and a gas fired steam unit, which when operated *with a gas* turbine in combined cycle mode, produces 85 MW of capacity. In addition to self generation capability, AEPCO's current power supply also includes hydroelectric power purchased from Western Area Power Administration (20.7 MW winter, 35.4 MW summer) and purchase power contracts with Public Service Co. of NM and Panda-Gila River Power.

OTHER POINTS OF INTEREST

AEPCO *no longer owns any* transmission facilities. Those assets were sold to Southwest Transmission Cooperative, Inc. *in* August 2001.

Arkansas Electric Cooperative Corporation

P.O. Box 194208
Little Rock, AR 72219-4208

Main Telephone (501) 570-2200
Main FAX (501) 570-2900
www.aecc.com

Executive Contacts

President/CEO .... *Gary Voigt*
Secretary to the President .... *Dianne Hopper*
Sr. Vice President & General Counsel .... *Robert M. Lyford*
Vice President/CFO .... *Michael Henderson*
Vice President, Governmental Affairs (AECI) .... *Carmie Henry*
Vice President, System Services .... *Doug White*
Vice President, Utility Sales & Services (AECI) .... *Pat McClafferty*
Vice President, Engineering, Construction & Operations .... *S. Maurice Robinson*
Vice President, Planning, Rates & Dispatching .... *Ricky Bittle*
Vice President, Information Technology .... *Robert McClanahan*

Accounting & Finance Related Personnel

Treasury .... *Michael Henderson*
Accounting .... *Lisa Sigler - Manager, AECC Accounting*
Property Accounting .... *Larry Helms - Manager, Accounting Services*
Internal Auditing .... *Kenneth Bland - Supervisor, Audits*
Employee Benefits .... *Don Parish - Manager, Human Resources*
Tax Accounting .... *David Walter - Manager, Tax & Insurance*

Ultimate Meters Served	470,000
REC Members	17
Other Firm Power Customers	1
Power Pool	SWPP
Total Plant Capacity	2,638 MW
# of Substations	27
Miles of Transmission Line	313
Total Employees	218
Union Employees	0
RUS Designation	AR 34

Taxable	Yes
State Regulated	Yes
Year Organized	1949
CPA - Tax	Deloitte & Touche, LLP
CPA - Audit	Deloitte & Touche, LLP

Corporate Insurance Providers

Worker's Comp	Ark. Self-Ins. Trust
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	AEGIS

2006 Financial Keys

Total Assets	$1,117,608,500
Total Operating Revenue	$605,562,276
Net Margins	$15,917,571
Equity Ratio	37.67%
T.I.E.R.	1.53
DSC Ratio	1.10
Cost of Debt	5.54%

MW Peak Demands

Winter	2,356
Summer	2,480

2006 MWH Sales

Member ... 12,018,796 @ $47.85 per MWH
Non-Mem .. 1,056,611 @ $28.48 per MWH

Arkansas Electric Cooperative Corporation

ORGANIZATION

The Arkansas Electric Cooperative Corporation (AECC) is a generation and transmission cooperative incorporated under the laws of the state of Arkansas headquartered in Little Rock. AECC, founded in 1949, is the wholesale power supplier for 17 electric distribution cooperatives in Arkansas.

MEMBERSHIP

Membership in AECC is composed of the 17 electric distribution cooperatives of Arkansas. These member cooperatives serve approximately 470,000 homes, farms, businesses and industries in Arkansas. Service territories assigned to the member cooperatives encompass more than 60% of Arkansas' land area. AECC is governed by a Board of Directors made up of the general manager and a director from each of its 17 members.

POWER SUPPLY

In 1963, AECC began generating power from the Fitzhugh Station, an oil/gas fired plant. Until that time, AECC's members purchased power from commercial power companies. In succeeding years, AECC built the Bailey and McClellan Stations, both oil/gas fired plants. It initiated co-ownership arrangements with Southwestern Electric Power Company and Entergy Arkansas, Inc. for 3 coal-fired plants—White Bluff, Independence & Flint Creek. In the early 1980's, AECC made a commitment to develop hydroelectric power generation on the Arkansas River. The first phase of that commitment was the Clyde T. Ellis Hydroelectric Generating Station, located at Lock & Dam #13 near Barling. It went into commercial operation in December 1988. The second phase of the project was the construction of the Carl S. Willock Hydroelectric Generating Station, located at Lock & Dam #9, near Morrilton, which went into commercial operation in October 1993. The third phase of the project was construction of the Electric Cooperatives of Arkansas Hydropower Generating Station, located at the Wilbur D. Mills Dam, which went into commercial operation in October 1999. During 2001, AECC completed the construction of a 153 MW natural gas-fired combustion turbine power plant near Fulton, Arkansas.

With AECC's demand for electricity growing at nearly 5 percent a year, AECC repowered the Fitzhugh plant, which added 112 megawatts of capacity to the 59 megawatt natural gas/oil fired plant. During 2005 AECC completed the acquisition of Wrightsville, a 548 MW natural gas fired combined-cycle power plant. AECC is currently evaluating the construction of additional base load facilities.

RESOURCES AVAILABLE TO AECC

Generation resources immediately available to AECC provide 2977 MW of capacity. Combining its current power supply of low-sulphur coal-fired and oil/gas-fired generating stations, hydroelectric power on the Arkansas River, and the addition of the combustion turbines, AECC and its member cooperatives are positioned to provide a dependable and economical supply of electricity. Committed to providing more than reliable power generation, AECC is striving to be a community developer—actively working to brighten the future of Arkansas and its people.

OTHER POINTS OF INTEREST

The mission of AECC is to assist each of its member cooperatives in improving the quality of life in the areas they serve through the delivery of electric power and other related services which address essential consumer needs. This is to be done at the lowest possible cost consistent with sound business practices.

FINANCIAL RATING INFORMATION

Latest Bond Rating AA-/AA-/A2*

*senior unsecured bonds

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Executive Contacts

Chief Executive Officer & General Manager	*Jim Jura*
Executive Assistant	*Janie Corn*
Chief Financial Officer	*David McNabb*
Director, Engineering & Operations	*Chris Bolick*
Director of Information Services	*Ron Murphy*
Director, Member Services & Corporate Communications	*Roger Clark*
Director, Human Resources	*Dave Stump*
Director, Power Production	*Duane Highley*
Controller	*Richard Burlison*

Accounting & Finance Related Personnel

Finance	*David McNabb*
Treasury	*Barbara Economon, Supervisor Treasury*
Accounting	*Jeannie Robbins, Manager*
Property Accounting	*Tina Wilson*
Tax Accounting	*Meredith Roberts*
Property & Liability Insurance	*Randy Murdaugh*
Internal Auditing	*Mike King - Manager, Internal Audit*
Data Processing	*Brad Austin - Manager, Procurement*
Employee Benefits	*Jana Woodall - Manager, Employee Benefits*
Resource Planning	*Brian Ackermann - Manager, Resource Planning*

Ultimate Meters Served	850,000
REC Members	6
Other Firm Power Customers	0
Power Pool	SERC
Total Plant Capacity	4,758 MW
# of Substations	17
Miles of Transmission Line	646
Total Employees	637
Union Employees	333
RUS Designation	MO 73

Taxable	Yes
State Regulated	No
Year Organized	1961
CPA - Tax	PricewaterhouseCoopers LLP
CPA - Audit	KPMG, LLP

Corporate Insurance Providers

Worker's Comp	Self-Insured
Primary Liability	Self-Insured
Commercial Umbrella	AEGIS/EIM
Electric Property	Lloyds of London

2006 Financial Keys

Total Assets	$1,821,765,076
Total Operating Revenue	$867,142,524
Net Margins	$15,522,756
Equity Ratio	16.39%
Margins for Interest	1.24
DSC Ratio	1.32
Cost of Debt	6.01%

MW Peak Demands

Winter	3,901
Summer	4,159

2006 MWH Sales

Member... 17,336,689 @ $32.77 per MWH
Non-Mem.. 5,060,753 @ $58.68 per MWH

ORGANIZATION

Associated Electric Cooperative, Inc. is an electric generation and transmission cooperative which provides wholesale electric service to its six members. Each of the six members in turn provides wholesale electric power to its *member distribution* cooperatives. The 51 distribution cooperatives that distribute power from Associated are engaged in the sale of electricity at retail to their member-consumers in Missouri, Oklahoma, and Iowa. Associated's *headquarters* are in *Springfield*, Missouri.

MEMBERSHIP

Associated's membership is comprised of six G&T cooperatives, five of which are located *in Missouri*. *The sixth* is located in Oklahoma. The Manager and a representative from the Board of each member G&T comprise the 12 representatives that make up Associated's Board of Directors. They set policy for Associated's role in the Electric *Cooperative* System, as well as wholesale electric rates for the six members.

POWER SUPPLY

The Thomas Hill Energy Center consists of three units, all owned and operated by Associated. The first two units were placed in service in 1966 and 1969 and have a net capacity of 180 MW and 303 MW respectively. The third unit was completed in 1982 and has a net capacity of 670 MW. Associated also has a two-unit 45 MW oil fired turbine generator at Unionville, Missouri. The New Madrid Power Station is made up of two units, 600 MW each. The first unit was completed in 1972 and is owned by the City of New Madrid. It was financed by revenue bonds issued by the City. Associated operates this plant under a 50-year agreement which entitles it to all of the output of the plant, except for that amount reserved for the City's use in operating its distribution system. Associated pays its proportionate share of the cost of the plant. The second unit was placed in service in 1977 and is owned and operated by Associated. At *year-end 2006*, Associated had 1,678 MW of gas-based generation on line. Associated has a long-term contract with the Southwestern Power Administration for 478 MW of hydroelectric peaking power.

TRANSMISSION

Associated and its six members have extensive transmission capabilities. The transmission network consists of 6,520 miles of 69kv lines, 227 miles of 138kv lines, 1,767 miles of 161kv lines, 658 miles of 345kv lines and 46 miles of 500kv lines, as well as the related substations. All substations, except 345kv and 500kv, are owned by Associated's members. Associated owns 599 miles of 345kv and 46 miles of 500kv lines. Associated, through an Electric Power Coordination Agreement with its members, pays the cost of owning, operating and maintaining everything above 69kv. Associated currently has interchange and interconnection agreements with 98 power suppliers in Missouri and adjacent states, which provide for 152 interconnection points between the transmission system and those of other power suppliers.

OTHER POINTS OF INTEREST

Beginning in 1991, Associated's bylaws were changed to allocate patronage in an amount equal to Associated's federal taxable income from its furnishing of electric energy and other services to its patrons. Asssociated's patronage capital rotation policy calls for the annual retirement of 2% of equity. Associated has added 1,633 MW of gas-based generation in the last six years. This 1,633 MW of *gas-based generation* includes 1,023 MW of combined-cycle turbines and 610 MW of simple-cycle peaking *units.*

Basin Electric Power Cooperative

1717 E. Interstate Avenue
Bismarck, ND 58503
www.basinelectric.com

Main Telephone (701) 223-0441
Main FAX (701) 224-5336
Accounting FAX (701) 255-5111

Executive Contacts

General Manager & CEO
Executive Assistant .... *Ron Harper*
Sr. Vice President & Deputy General Manager .... *Linda Thomas*
Sr. Vice President, Generation .... *Paul Sukut*
Sr. Vice President, Transmission .... *Wayne Backman*
Sr. Vice President & CFO .... *Mike Risan*
Sr. Vice President, Chief Information Officer .... *Clifton (Buzz) Hudgins*
Sr. Vice President, External Relations & Communication .... *Patrick Spilman*
Sr. Vice President & General Counsel .... *Mike Eggl*
.... *Claire Olson*

Accounting & Finance Related Personnel

Tax & Insurance
Treasury Services .... *Rod J. Kuhn - Manager*
Financial Operations .... *Steve Johnson - Manager*
Accounting .... *Karen Crawford - Manager*
Financial Planning & Forecasting .... *Shawn Deisz - Manager*
Capital Assets .... *Dave Bangen - Manager*
Financial Reporting & Accounts Receivable .... *Craig Laub - Supervisor*
Income Tax .... *Kim Wetzel - Supervisor*
Accounts Payable .... *Deb Olafson - Supervisor*
State & Local Tax .... *Pat Meidinger - Supervisor*
Insurance - Plant .... *Don Boehm - Supervisor*
Payroll .... *Evan Mandigo - Director of Risk & Insurance*
Resource Planning .... *Blair Mitzel - Supervisor*
.... *Wayne Backman*

Ultimate Meters Served	998,000
REC Members	19
Other Firm Power Customers	2
Power Pool	MRO,WSCC,RMRG
Total Plant Capacity	2,499 MW
# of Substations & Switch yards	56
Miles of Transmission Line	1,790
Total Employees	1,123
Union Employees	535
RUS Designation	ND 45
Taxable	Yes

State Regulated	No
Year Organized	1961
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Deloitte & Touche LLP

Corporate Insurance Providers

Worker's Comp.	States & Liberty Mutual
Primary Liability	Old Republic
Commercial Umbrella	AEGIS/EIM
Electric Property	FM Global

2006 Financial Keys

Total Assets	$2,879,776,889
Total Operating Revenue	$628,716,081
Net Margins	$5,080,605
Equity Ratio	26.93%
Margins for Interest	1.32
DSC Ratio	N/A
Cost of Debt	5.58%

MW Peak Demands

Winter	2,334
Summer	2,399

2006 MWH Sales

Member ... *11,849,000 @ $30.73* per MWH
Non-Mem .. 6,119,000 @ $41.24 per MWH

Basin Electric Power Cooperative

ORGANIZATION

Founded in 1961, Basin Electric is a cooperative corporation organized and existing under the laws of the State of ND. It serves member electric service needs in a nine state region of ND, SD, MT, WY, CO, NM, MN, and IA. Basin Electric has four wholly owned for-profit subsidiaries, Dakota Gasification Company (DGC), Dakota Coal Company (Dakota Coal), Basin Telecommunications, Inc., and Granite Peak Energy, Inc., and a wholly owned not-for-profit subsidiary, Basin Cooperative Services. DGC has a wholly owned for-profit subsidiary, Souris Valley Pipeline, Limited. Dakota Coal also has a wholly owned for-profit subsidiary, Montana Limestone Company. Basin Electric is also a 42.27% owner of the Missouri Basin Power Project and serves as the Operating Agent for the 1650 MW Laramie River Station in WY. With its subsidiaries, Basin Electric is a diversified energy group that generates electricity, contracts for resale of lignite, produces lime, sells telecommunications services and produces natural gas and byproducts through the coal gasification process.

MEMBERSHIP

Basin Electric has four membership classifications. Class A consists of eight G&T cooperatives and 10 distribution cooperatives that have long-term wholesale power contracts with Basin Electric.

Basin Electric has 98 Class C member distribution cooperatives and public power districts that are members of Basin's eight wholesale G&T Class A members. There are currently three Class D members that purchase a fixed amount of power under intermediate term contracts. There is currently one Class B member. Basin Electric's member systems serve approximately 2.5 million people in a nine state region.

POWER SUPPLY

Basin Electric operates 3,508 MW of electric generating capacity of which 2,555 MW is for its own use. The Cooperative operates the other 953 MW at the Laramie River Station near Wheatland, WY for the Missouri Basin Power Project. Basin Electric also owns 50% of the 80 MW Earl F. Wisdom Generating Station Unit 2 operated by Corn Belt Power Cooperative. Basin Electric purchases Northwest Iowa Power Cooperative's uncommitted share of 33 MW in Unit 4 of George Neal Station.

TRANSMISSION

The geographic area served by Basin Electric's members is separated into eastern and western transmission systems, as a result of the historical development in the United States of two separate transmission systems.

Basin Electric has transmission and generation assets located within both of these electrical systems and is a member of the Midwest Reliability Organization, the Western System Coordinator's Council, and the Rocky Mountain Reserve Group.

Big Rivers Electric Corporation

P.O. Box 24
Henderson, KY 42419-0024

Main Telephone (270) 827-2561
Main FAX (270) 827-2558
www.bigrivers.coop

Executive Contacts

President & CEO .... *Michael H. Core*
Executive Secretary .... *Paula Mitchell*
Vice President, Financial Services & CFO .... *C. William Blackburn*
Vice President, System Operations .... *David G. Crockett*
Vice President, Power Supply .... *C. William Blackburn*
Vice President, External Affairs & CPO .... *David A. Spainhoward*
Vice President, Special Projects .... *Travis D. Housley*
Vice President, Administrative Services .... *James V. Haner*

Accounting & Finance Related Personnel

Finance .... *C. William Blackburn*
Treasury .... *C. William Blackburn*
Accounting .... *Ralph Ashworth-Manager, Accounting*
Property Accounting .... *Ralph Ashworth*
Tax Accounting .... *Ralph Ashworth*
Insurance-Plant .... *James V. Haner*
Data Processing .... *David Titzer-Manager, Information Systems*
Employee Benefits .... *James V. Haner*
Resource Planning .... *C. William Blackburn*

Ultimate Meters Served	109,979
REC Members	3
Other Firm Power Customers	N/A
Power Pool	N/A
Total Plant Capacity	1,459 MW
# of Substations	23
Miles of Transmission Line	1,232
Total Employees	104
Union Employees	25
RUS Designation	KY 62

Taxable	Yes
State Regulated	Yes
Year Organized	1961
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Deloitte & Touche LLP

Corporate Insurance Providers

Worker's Comp.	KESA
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Chubb

2006 Financial Keys

Total Assets	$1,254,388,382
Total Operating Revenue	$230,236,571
Net Margins	$34,542,297
Equity Ratio	-17.33%
T.I.E.R.	1.47
DSC Ratio	1.86
Cost of Debt	5.83%

MW Peak Demands

Winter	593
Summer	631

2006 MWH Sales

Member ..... 3,188,056 @ $34.11 per MWH
Non-Mem .. 2,062,286 @ $39.81 per MWH

ORGANIZATION

Headquartered in Henderson, Kentucky, Big Rivers Electric Corporation is a generation and transmission cooperative owned by the members it serves. Big Rivers provides reliable wholesale electric service on a not-for-profit basis to its *three member* cooperatives. In turn, these cooperatives, owned by their 109,979 consumer-members, distribute the electricity at retail, on a not-for-profit basis, in portions of 22 counties located in western Kentucky.

MEMBERSHIP

Big Rivers' Board of Directors is comprised *of six directors. Each of the three distribution* cooperatives has two of its members serving on Big Rivers' Board. The Board normally meets once each month and is responsible for setting corporate policy.

POWER SUPPLY

On July 17, 1998, Big Rivers completed a transaction with LG&E Energy Corporation (LEC) to lease the 1,459 MW of generating capacity it owns. In addition, Big Rivers' capacity rights in the Henderson Municipal Power and Light (HMP&L) Station Two facility (under an operating agreement with HMP&L) was assigned to LEC.

The LEC lease transaction includes a Purchase Power Agreement whereby Big Rivers purchases from LG&E Energy *Marketing, Inc. (LEM—a subsidiary of LEC)* certain minimums and maximums of energy at fixed costs throughout the 25-year lease agreement. Additionally, Big Rivers has available to it 178 MW of hydroelectric peaking capacity through a long-term contract with the Southeastern Power Administration (SEPA). Power requirements not met through the LEM and SEPA agreements are obtained by accessing the wholesale power market.

Under the Purchase Power Agreement with LEM, Big Rivers has available for purchase and resale, off-system if economically viable, any power in excess of its member requirements up to its established maximum. Big Rivers can also purchase power from other sources for resale to either members or off-system when market conditions are economically favorable.

The *facilities* leased under the LEC transaction consist of 1,394 MW of coal-fired steam and 65 MW of oil/natural gas-fired *internal combustion generating* capacity. The Reid plant has a net capacity of 130 MW, 65 MW of which is the combustion turbine. The Kenneth C. Coleman Plant *consists of three* units totaling 455 MW of net capacity. Big Rivers has two units totaling 454 MW at its Robert D. Green Plant. The D.B. Wilson Plant has a net capacity of 420 MW.

TRANSMISSION

Big Rivers owns and operates its transmission system and provides *transmission services to its members, LEM,* and other third parties in accordance with its open access transmission tariff. The *transmission system is comprised of* approximately 1,232 miles of line—67 miles of 345 kV line for interconnecting power plants; 336 miles of 161 kV line for bulk power transmission, interconnections, and service to large industries; 14 miles of 138 kV line for bulk power transmission and interconnections; and 815 miles of 69 kV line for sub-transmission power delivery. Big Rivers has physical interconnections with six utilities and an interchange agreement with another utility.

OTHER POINTS OF INTEREST

On April 18, 2000, Big Rivers completed a sale-leaseback of two of its utility plants, including the related facilities and equipment. This transaction has been recorded as a financing for financial reporting purposes and a sale for Federal income tax purposes.

Brazos Electric Cooperative, Inc.

P.O. Box 2585
Waco, TX 76702-2585

Main Telephone (254) 750-6500
Main FAX (254) 750-6229
brazoselectric.com

Executive Contacts

Executive Vice President & General Manager	*Clifton B. Karnei*
Administrative Assistant	*Candace Denton*
Manager Human Resources	*Tom Yows*
Vice President Services	*Khaki Bordovsky*
Vice President Transmission	*Johnny York*
Vice President Planning & Marketing	*Hugh Lenox*
Vice President Generation	*David Murphy*
Manager, Communication/Key Accounts	*Kyle Minnix*

Accounting & Finance Related Personnel

Finance	*Khaki Bordovsky*
Treasury	*Brent Fox - Manager, Fiscal Services & Controller*
Accounting	*Brent Fox*
Property Accounting	*Brent Fox*
Tax Accounting	*Brent Fox/Khaki Bordovsky*
Internal Auditing	*Khaki Bordovsky*
Insurance Plant	*Brent Fox*
Data Processing	*Rod Little - Manager, Technology Services*
Employee Benefits	*Tom Yows*

Ultimate Meters Served	439,364	Taxable	No
REC Members	17	State Regulated	Yes
Other Firm Power Customers	2	Year Organized	1941
Power Pool	ERCOT	CPA - Tax	PricewaterhouseCoopers LLP
Total Plant Capacity	1,567 MW	CPA - Audit	PricewaterhouseCoopers LLP
# of Substations	377	**Corporate Insurance Providers**	
Miles of Transmission Line	2,577	Worker's Comp	AIG
Total Employees	354	Primary Liability	AIG
Union Employees	0	Commercial Umbrella	AIG
RUS Designation	TX 121	Electric Property	Starr Tech/Zurich

2006 Financial Keys

Total Assets	$1,493,901,731
Total Operating Revenue	$880,892,682
Net Margins	$43,656,430
Equity Ratio	13.93%
T.I.E.R.	2.07
DSC Ratio	1.91
Cost of Debt	4.81

MW Peak Demands

Winter	2,308
Summer	2,613

2006 MWH Sales

Member	N/A
Non-Mem	N/A

Brazos Electric Cooperative, Inc.

ORGANIZATION

Brazos Electric Power Cooperative is a generation and transmission electric utility organized in 1941 to provide reliable, low-cost power to its 17 member cooperatives which serve consumers in 68 counties in Texas. Brazos Electric 's Board of Directors is comprised of one representative from each of its member cooperatives.

MEMBERSHIP

The financial strength and resilience of Brazos Electric stem from its wholesale customers, which serve about 439,364 rural, suburban and urban meters in a 57,000 square mile area that covers more than 20% of Texas. This vast service area provides a diversity of residential, agricultural, mining, oil-field and industrial loads. About 61% of Brazos Electric's ultimate load is residential. The largest single industrial load is about 45 Megawatts.

RATES AND REGULATION

The transmission rates, charged by the cooperative, are regulated by the Public Utility Commission of Texas. All other rates are set by the Board of Directors

POWER SUPPLY

The Cooperative's generating capacity includes four natural gas-fired plants; (1) the Randle W. Miller Plant, with five units totaling 611 MW in Palo Pinto County; (2) the three-unit North Texas Plant with 75.5 MW in Parker County; (3) the Johnson County Generation Facility, which is a 258 MW combined cycle plant located in Johnson County; and (4) the Jack County Generation Facility, a 600 MW combined cycle plant in Jack County, Texas.

Brazos Electric purchases 195.5 MW from the lignite-fired San Miguel Plant through a life-of-plant contract, 54 MW of hydro-electric power through long-term contracts, and the balance of its requirements from other power suppliers.

TRANSMISSION

Brazos' 2,577 miles of transmission line provide service for 377 substations and metered points of delivery. The transmission lines include 96 miles of 345 kilovolt line, 1,259 of 138 kilovolt line, and 1,218 miles of 69 kv line.

A growing number of member cooperatives are connected to Brazos Electric's Energy Management System through Supervisory Control and Data Acquisition (SCADA) systems. The SCADA systems allow Brazos Electric and participating member cooperatives to use special equipment that responds to problems quickly and reroutes power by remote control.

OTHER POINTS OF INTEREST

Brazos operates three natural gas pipelines and conducts studies of fuel delivery options and storage projects to provide additional savings to the members of Brazos Electric.

P.O. Box 26036
Columbus, OH 43226-0036

Main Telephone (614) 846-5757
Main FAX (614) 846-7108
www.buckeyepower.com

Executive Contacts

President	*Anthony J. Ahern*
Executive Assistant	*Ann Lamber*
Vice President, Finance	*Bobby L. Daniel*
Vice President, Engineering & Power Supply	*Patrick O'Loughlin*
Vice President, Administration & Operations	*David A. Berger*
Vice President, Corporate Planning (Resource Plng. Assoc. Contact)	*Peter Buros*

Accounting & Finance Related Personnel

Finance	*Bobby L. Daniel*
Treasury	*Kerrie Dugan*
Accounting	*James J. Palmisano*
Property Accounting	*Donna Cole*
Tax Accounting	*James J. Palmisano*
Internal Auditing	*Michael Shott*
Insurance Plant	*Bobby L. Daniel*
Data Processing	*Greg Niese*

Ultimate Meters Served	373,800
REC Members	25
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	1,488 MW
# of Substations	2
Miles of Transmission Line	0
Total Employees	32
Union Employees	0
RUS Designation	OH 99

Taxable	No
State Regulated	No
Year Organized	1949
CPA - Audit	BDO Seidman/GBQ Partners

Corporate Insurance Providers

Worker's Comp.	State Pool
Primary Liability	Federated
Commercial Umbrella	EIB
	/EIM/AEGIS/Lloyds/XL Insurance
Electric Property	Factory Mutual Global

2006 Financial Keys

Total Assets	$923,957,611
Total Operating Revenue	$354,577,815
Net Margins	$36,149,623
Equity Ratio	35.75%
T.I.E.R.	2.67
DSC Ratio	1.35
Cost of Debt	5.33%

MW Peak Demands

Winter	1,424
Summer	1,556

2006 MWH Sales

Member	7,904,419 @ $41.59 per MWH
Non-Mem	326,818 @ $47.97 per MWH

ORGANIZATION

Buckeye Power, Inc. (Buckeye) provides wholesale electric service to its 25 members constituting all of the electric distribution cooperatives engaged in the sale of electricity in Ohio. Buckeye is a non-profit corporation operating on a cooperative basis, and is exempt from federal income tax under section 501 C (12) of the Internal Revenue Code. Buckeye was incorporated in 1949, and began providing generation services in 1968.

MEMBERSHIP

Each of Buckeye's Distribution Cooperative members is represented on Buckeye's 25 seat Board of Trustees. Combined, the Distribution Member Cooperatives serve over 373,800 customers over 47,885 miles of line. Buckeye's Distribution Cooperative members serve at least portions of 77 of Ohio's 88 counties.

POWER SUPPLY

Buckeye's Member Distribution cooperatives have entered into long term all requirements contracts with Buckeye. Buckeye owns two of the three units at the Cardinal Station (Cardinal) along the Ohio River near Brilliant, OH. These two coal-fired units have a capacity of 1,230 MW. A 600 MW unit at Cardinal is owned by Ohio Power Company (Ohio Power). Cardinal is managed and operated as a single facility by Cardinal Operating Company (COC) as agent for the owners of the individual units. The operating costs of Cardinal are apportioned between the owners as specified in a Station Agreement among Buckeye, Ohio Power, and COC. The Station Agreement also contains provisions which allow Buckeye to purchase energy from Ohio Power to back up Buckeye's units under certain conditions.

Buckeye has entered into a Power Purchase Agreement with National Power Cooperative, Inc., which is a wholly-owned subsidiary of Ohio Rural Electric Cooperatives, Inc., the Ohio Statewide Association. In July 2002, National's 510 MW Robert P. Mone Station went commercial.

On December 31, 2004, Buckeye Power Generating LLC (Buckeye Generating), a wholly-owned subsidiary of Buckeye, purchased the nine percent interest of Allegheny Energy Supply Company in the Ohio Valley Electric Corporation (OVEC). OVEC is owned by several Investor Owned Utilities in the Ohio Valley Region. Buckeye Generating's ownership in OVEC provides for up to 203 MW of coal-based capacity from the OVEC units under the terms of the Inter-Company Power Agreement between OVEC and its owners.

On December 21, 2006, Buckeye entered into an Asset Purchase Agreement with DPL Energy, LLC (DPLE), an affiliate of DPL Inc., for it's Greenville, OH combustion turbine generating station. The purchase will add approximately 200 MW of peaking capacity to Buckeye's power generation portfolio. Buckeye and DPLE completed the transaction on April 25, 2007.

Buckeye also has a 55 MW entitlement from the New York Power Authority.

OTHER POINTS OF INTEREST

Buckeye purchases transmission service under Federal Energy Regulatory Commission tariffs, administrated by PJM Interconnection, LLC and the Midwest Independent Transmission System Operator, Inc. Buckeye management is also evaluating alternatives for providing additional generating resources to serve its Distribution Members Cooperatives' future needs. Buckeye has incurred significant expenditures for pollution control equipment at Cardinal, and anticipates that further expenditures will be necessary.

P.O. Box 269
Jefferson City, MO 65102

Main Telephone (573) 634-2454
Main FAX (573) 634-3892

Executive Contacts

CEO/General Manager	*Donald W. Shaw*
Manager of Finance	*Randy Carrender*
Manager of Engineering & Operations	*Ralph J. Schulte*
Power Plant Superintendent	*Tim Backes*
Manager of Administrative Services	*Mark Newbold*
Director of Economic & Community Development	*Nancy Gibler*
Information Technology	*Kenny Nilges*

Accounting & Finance Related Personnel

Finance	*Randy Carrender*
Treasury	*Randy Carrender*
Accounting	*Larry Bedsworth - Financial Accountant*
Property Accounting	*Kirby Ernst - Property Accountant*
Tax Accounting	*Randy Carrender*
Internal Auditing	*Randy Carrender*
Insurance Plant	*Randy Carrender*
Information Technology	*Kenny Nilges*
Employee Benefits	*Mark Newbold*
Resource Planning	*Ralph Schulte*

Ultimate Meters Served	170,000
REC Members	8
Other Firm Power Customers	*0*
Power Pool	Associated
Total Plant Capacity	67 MW
# of Substations	*116*
Miles of Transmission Line	1,579
Total Employees	120
Union Employees	*54*
RUS Designation	MO 71

Taxable	No
State Regulated	No
Year Organized	1949
CPA - Tax	Wade Stables
CPA - Audit	Wade Stables

Corporate Insurance Providers

Worker's Comp	MECIP
Primary Liability	Federated
Commercial Umbrella	AEGIS
Electric Property	Federated

2006 Financial Keys

Total Assets	$193,552,854
Total Operating Revenue	$116,090,344
Net Margins	$6,240,482
Equity Ratio	52.80%
T.I.E.R.	2.55
DSC Ratio	1.49
Cost of Debt	5.17%

MW Peak Demands

Winter	734
Summer	754

2006 MWH Sales

Member	3,253,019 @ $35.42 per MWH
Non-Mem	0

ORGANIZATION

Central Electric Power Cooperative was formed in 1949 as an electric generation and transmission cooperative.

MEMBERSHIP

Central's Board of Directors consists of two representatives from each of its eight rural Electric Cooperative (REC) members. This Board sets policy and wholesale electric rates for the member system. The member *distribution* systems have "all requirements" contracts with Central which stipulate that the members must buy all of their power supply requirements from Central.

POWER SUPPLY

Central is an "all requirements" member/ owner of Associated Electric Cooperative, *Inc. (AECI) of Springfield, Missouri.* All of Central's power needs are satisfied by AECI. AECI was created by Central and the five *other G&T cooperatives operating in Missouri* in 1961. The goal was to establish a "Super G&T" which could satisfy the needs of the six wholesalers serving *41 Rural Electric* Cooperatives in Missouri and 3 REC's in Iowa. The 67 mw coal-fired Chamois Power Plant was built by Central during the 1950's. The two units continue to be operated by Central and are contracted to the AECI system which pays the *operating costs and schedules* the generation.

TRANSMISSION

Central owns 1,579 miles of 69 and 161 kv transmission line, 103 *distribution substations* and 13 transmission substations. Central also provides maintenance services for 59 miles of AECI owned 345 kv line, two 345 kv substations, and the switchyard facilities located at Thomas Hill Power Plant. Approximately one-third of the total load delivered to the distribution member systems is supplied directly from the 161/69 kv transmission tie substations and unburdens the aging 69 kv transmission system.

OTHER POINTS OF INTEREST

Since 1949, Central has allocated $105,291,311 in margins to our member cooperatives. Central has retired all capital credit allocations through 1993, resulting in an unretired allocated capital of $57,081,989.

Central provides numerous support service for the member distribution systems including data processing and programming service, technical and engineering assistance, large power load metering, electronic reclosers, system control and data acquisition *(SCADA) terminals* at each member's office and after hours outage answering service.

The ability of Central's members to *compete favorably with outside threats* over the next decade seems certain. Stable rates territorial integrity and reliable power supply *combine to make a "Cooperative Powered"* Missouri a certainty for many years to come.

P.O. Box 1455
Columbia, SC 29202

Main Telephone (803) 779-4975
Main FAX (803) 252-8047

Executive Contacts

President & CEO	*Ron Calcaterra*
Senior Vice President & General Counsel	*Art Fusco*
Senior Vice President Transmission & Engineering Services	*Tim Powell*
Director of Power Supply	*David Logeman*
Vice President & CFO	*John Brantley*
Director of Information Services	*Jerry Hagenmaier*

Accounting & Finance Related Personnel

Finance	*John Brantley*
Treasury	*Margot Ewing - Treasury Coordinator*
Accounting	*Jeff Lewis - Chief Accountant*
Property Accounting	*Amy Longtine - Sr. Financial Analyst*
Tax Accounting	*Cynthia Hickman - Manager, Financial Analysis*
Financial Analysis	*Cynthia Hickman*
Insurance Plant	*Art Fusco*
Data Processing	*Jerry Hagenmaier*
Employee Benefits	*Tina Smedes - Human Resources Coordinator*
Resource Planning	*David Logeman*

Ultimate Meters Served	502,665
REC Members	15
Other Firm Power Customers	1
Power Pool	N/A
Total Plant Capacity	0 MW
# of Substations	0
Miles of Transmission Line	475
Total Employees	35
Union Employees	0
RUS Designation	SC 50

Taxable	No
State Regulated	No
Year Organized	1948
CPA - Tax	N/A
CPA - Audit	PricewaterhouseCoopers LLP

Corporate Insurance Providers

Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	None

2006 Financial Keys

Total Assets	$193,755,837
Total Operating Revenue	$775,455,976
Net Margins	$1,133,419
Equity Ratio	9.89%
T.I.E.R.	1.32
DSC Ratio	1.10
Cost of Debt	4.91%

MW Peak Demands

Winter	3,237
Summer	3,041

2006 MWH Sales

Member	13,492,954 @ $57.49 per MWH
Non-Mem	0

ORGANIZATION

Central Electric Power Cooperative, Inc. (Central) was incorporated and organized in 1948, with headquarters located in Columbia, South Carolina. Central provides total wholesale electric service to 15 of South Carolina's 20 retail electric cooperatives serving over 502,665 residential, commercial, and industrial meters. In addition, Central provides supplemental power to Saluda River Electric Cooperative, another G&T serving the other 5 retail electric cooperatives who serve over 183,305 meters. Central has no direct generation ownership; the cooperative designs and builds transmission lines between the bulk transmission system and member delivery points.

MEMBERSHIP

Central has 16 Corporate members. Fifteen are retail electric cooperatives served through long-term, all-requirements power supply contracts. The other member is another G&T cooperative association in South Carolina with five retail electric cooperative members and is served through a supplemental requirements contract. Central's public utility activities are directed by its Board of Trustees. The Board consists of two representatives from each of Central's 16 members.

POWER SUPPLY

Central purchases the majority of its power from the South Carolina Public Service Authority through a long-term contract. The remainder of Central's power supply needs are met with power purchased from the Southeastern Power Administration and South Carolina Electric and Gas Co.

TRANSMISSION

The bulk of Central's transmission system was designed to service the coordinated and integrated Central/SCPSA system. The transmission grid consists of over 2,000 miles of 115 kV and 230 kV lines constructed by Central and leased to SCPSA. Central owns 197 *miles of 115 kV line and 278 miles of 69* kV line.

REGULATION

Central's rates are not subject to regulation by the South Carolina Public Service Commission or the Federal Energy Regulatory Commission.

TAX STATUS

As a *nonprofit electric cooperative*, Central is exempt from Federal taxation under Section 501(C) (12) of the Internal Revenue Code. Accordingly, no provision for income taxes is made. As provided in the bylaws, any margin excess or deficiency is treated as an advance from or return of capital to the members and is allocated to each member based on the percentage of their respective energy purchases during the year.

OTHER POINTS OF INTEREST

The Cooperative has a margin stabilization plan which, in effect, requires the Cooperative to adjust electrical rates to members to achieve defined margins. Effective January 1, 2004, Central's Board defined the required margins to achieve a Times Interest Earned Ratio of 1.10 plus the reimbursement of a portion of the costs incurred for land and right-of-way easements on transmission projects. Actual margins above or below the established margin are deferred and recognized in the subsequent year.

FINANCIAL RATING INFORMATION

Standard & Poors.............................AA

P.O. Box 2517
Cedar Rapids, IA 52406

Main Telephone (319) 366-8011
Main FAX (319) 366-8626
www.cipco.net

Executive Contacts

Executive Vice President & Chief Executive Officer	*Dennis L. Murdock*
Executive Assistant	*Denise Himes*
Vice President of Utility Operations	*Richard Anderson*
Chief Operating Officer/Vice President of Business Operations	*Craig Fricke*
CFO/Assistant Vice President	*Terry Sullivan*
Dir. Of Bus. Development/Assistant Vice President	*Patrick Murphy*

Accounting & Finance Related Personnel

Finance	*Terry Sullivan*
Treasury	*Michelle Soyer - Controller*
Accounting	*Michelle Soyer*
Property Accounting	*Jim Butikofer - Accountant*
Tax Accounting	*N/A*
Internal Auditing	*N/A*
Insurance Plant	*Jim Albertson - Manager, Human Resources*
Data Processing	*Donald Chaon - Manager, Data Systems*
Employee Benefits	*Jim Albertson – Manager, Human Resources*
Resource Planning	*Jerry Barker - Director of Enterprise Risk Mgmt.*

Ultimate Meters Served	127,000
REC Members	12
Other Firm Power Customers	1
Power Pool	MRO
Total Plant Capacity	393 MW
# of Substations	25
Miles of Transmission Line	2,002
Total Employees	110
Union Employees	53
RUS Designation	IA 83

Taxable	No
State Regulated	No
Year Organized	1946
CPA - Tax	LWBJ
CPA - Audit	KPMG, LLP

Corporate Insurance Providers

Worker's Comp.	AIG
Primary Liability	Chubb
Commercial Umbrella	St. Paul
Electric Property	Travelers

2006 Financial Keys

Total Assets	$462,198,104
Total Operating Revenue	$140,111,115
Net Margins	$9,970,599
Equity Ratio	16.80%
T.I.E.R.	1.61
DSC Ratio	1.17
Cost of Debt	5.73%

MW Peak Demands

Winter	442
Summer	543

2006 MWH Sales

Member	2,451,023 @ $56.54 per MWH
Non-Mem	0

WHO WE SERVE

CIPCO *is the wholesale* electric power supplier for 12 rural electric cooperatives and one municipal cooperative, serving 14 municipal systems across the state of Iowa. The member systems in turn distribute power to approximately 312,000 Iowans in 58 counties. In order for CIPCO to supply the needed electric power and energy for these Iowans, it owns power generating stations. *Some of the plants are owned* and operated by CIPCO. Some are owned in partnership with other utilities and are operated and maintained through contractual arrangements with these utilities.

GENERATIONS FACILITIES

CIPCO has a diverse mix of generation resources. *Its power and energy is produced* from nuclear generation, coal fired units, natural gas and oil fired plants, wind and hydro power. CIPCO has a percentage of ownership in the nuclear fueled facility, the Duane Arnold Energy Center at Palo, Iowa; and two coal-fired plants, the Council Bluffs Unit No. 3, Council Bluffs, Iowa, and the Louisa Generating Station, Muscatine, Iowa. *Fair Generating Station*, Montpelier, Iowa, is a wholly-owned CIPCO coal-fired plant. The Summit Lake Station at Creston, Iowa is owned by CIPCO and is fueled by oil and natural gas. CIPCO also purchases small amounts of power from hydro-electric systems of the Western Area Power Administration, and other regional utilities on a contractual basis. Combined, these facilities *and purchases supply* the total needs of CIPCO's members.

TRANSMISSION LINES

Just as in the case of joint ownership of generation facilities, it has always been the philosophy of CIPCO that the most economical method of transmitting power from the generating station *to the member* is by joint use of transmission facilities and common use of operation and maintenance personnel and equipment. From its inception in 1946, CIPCO has minimized its transmission investment and operations and maintenance expenses by entering into contracts with other utilities to share in the use of transmission lines, substations, operating *personnel and* equipment. This philosophy has created an integrated system of transmission and substation facilities which stretches over 300 miles diagonally across the state from Dubuque on the Mississippi River to Shenandoah in southwest Iowa. The electricity needed by CIPCO's members is carried from the power plants to nearly 250 local distribution substations through a network *of over 2,000 miles* of transmission lines and high voltage substations.

OPERATIONS OFFICES

The headquarters of Central Iowa Power Cooperative is located in Cedar Rapids, Iowa. Operations offices are at Creston and Wilton. Over 100 employees are presently employed by the Cooperative *at these locations*, including those at Fair Station and Summit Lake. CIPCO was originally organized to provide all power requirements for its member systems, and that is still true today. The Cooperative continues to offer the members reliable service at the lowest possible cost.

FINANCIAL RATINGS INFORMATION

Standard & Poor's	A
Fitch	A-

Central Montana Electric Power Cooperative, Inc.

501 Bay Drive
Great Falls, MT 59404

Main Telephone (406) 268-1211
Main FAX (406) 268-1205
www.cmepc.org

Executive Contacts

Manager .... *Thomas R. Huntley*

Ultimate Meters Served	26,595	Taxable	No
REC Members	10	State Regulated	No
Other Firm Power Customers	0	Year Organized	1961
Power Pool	N/A	CPA - Tax	N/A
Total Plant Capacity	0 MW	CPA - Audit	Smith, Lange & Associates
# of Substations	0	**Corporate Insurance Providers**	
Miles of Transmission Line	0	Worker's Comp	Self-Insured Pool
Total Employees	2	Primary Liability	NFU
Union Employees	0	Commercial Umbrella	NFU
RUS Designation	N/A	Electric Property	NFU

2006 Financial Keys

Total Assets	$7,316,861
Total Operating Revenue	$15,445,739
Net Margins	$4,561,955
Equity Ratio	N/A
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	N/A

MW Peak Demands

Winter	90
Summer	88

2006 MWH Sales

Member	Unavailable
Non-Mem	0

THE CENTRAL MONTANA STORY

Central Montana is an association of 14 rural electric cooperatives in Montana organized for the purpose of providing low cost wholesale electric power to those cooperative members. The organization was incorporated as a non-profit rural electric wholesale power supplier in 1961. Over the years, it has evolved into a very effective power supply utility, acquiring power from a diversified electrical generation base. Three entities supply Central Montana electricity - those are Western Area Power Administration, Montana Power Company, and Basin Electric Power Cooperative. Central Montana blends that power into one uniform rate and resells it to its members.

Primary benefits of Central Montana to its members are low-cost wholesale power, long-term favorable power supply contracts, diversified power supply (three power suppliers), unified strong voice in power supply, broad-based member support (14 members).

Headquartered in Great Falls, Montana, Central Montana is small but efficient - operating with two employees. It has no generation or transmission facilities. Its members serve more than half the area of Montana.

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525 20th Avenue SW
Minot, ND 58701-6436

Main Telephone (701) 852-4407
Main FAX (701) 852-4401
www.centralpwr.com

Executive Contacts

General Manager	*Thomas L. Meland, PE*
Executive Assistant	*Kandace D'Ambrosio*
Manager of Accounting & Finance	*Michael J. Kossan, CPA*
Manager of Operations & Engineering	*Mark Sherman, PE*

Accounting & Finance Related Personnel

Finance	*Michael J. Kossan, CPA*
Treasury	*Michael J. Kossan, CPA*
Accounting	*Michael J. Kossan, CPA*
Property Accounting	*Michael J. Kossan, CPA*
Tax Accounting	*Michael J. Kossan, CPA*
Internal Auditing	*Michael J. Kossan, CPA*
Insurance Plant	*Dave Klein*
Computer/Network Administration	*Todd Ahmann*
Employee Benefits	*Dave Klein*
Resource Planning	*Michael J. Kossan, CPA*

Ultimate Meters Served	50,834
REC Members	6
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	0 MW
# of Substations	140
Miles of Transmission Line	946
Total Employees	37
Union Employees	23
RUS Designation	ND 42

Taxable	No
State Regulated	No
Year Organized	1949
CPA - Tax	N/A
CPA - Audit	Eide Bailly LLP

Corporate Insurance Providers

Worker's Comp	State Funded
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$67,247,345
Total Operating Revenue	$47,919,538
Net Margins	$2,035,553
Equity Ratio	40.61%
T.I.E.R.	2.14
DSC Ratio	1.65
Cost of Debt	5.51%

MW Peak Demands

Winter	280
Summer	192

2006 MWH Sales

Member	1,411,511 @ $31.57 per MWH
Non-Mem	0

ORGANIZATION

In the late 1930's and early 1940's, most of central North Dakota's rural electrical energy supply was provided to the cooperatives' distribution systems through the lines of two investor owned utilities. Growth in demand for electricity in the rural areas was straining this supply. The rural cooperatives realized that they were at a crossroads in electrical supply planning, and that the prudent course for long-term cooperative stability was the establishment of independent, reliable long-term supplies of energy.

The shortage of power, coupled with the need for electrical transmission capability between the developing hydro-electric facilities and the consumers, led to the formation of Central Power Electric cooperative in the year 1949.

Central Power was incorporated as a generation and transmission cooperative, created to supply and deliver wholesale electrical energy to its six member rural electric cooperatives. To this end, a loan was obtained from the Rural Utilities Service (RUS) to build a generating plant. This plant, located in Velva, North Dakota, was completed and went on line in 1952, and, at that time, was the largest pulverized lignite burning plant in the U.S.

To transmit the power to the member distribution cooperatives, Central Power established wheeling contracts with Otter Tail Power and power supply contracts with the Bureau of Reclamation, as well as building some of its own transmission line and several transmission stations. These Central Power contracts and facilities augmented the separate contracts and facilities of the individual member cooperatives in order to form a comprehensive power supply system.

POWER SUPPLY & TRANSMISSION

In 1964 Central Power joined other regional G&T's in becoming a member of Basin Electric. Central Power worked with others to achieve further regional power coordination during this period by helping to organize the Missouri Basin Systems Group and the Mid-West Electric Consumers Association.

In the later 1960's development of Basin Electric's power capability and changing member needs led to a study focusing on changes in Central Power's mission of electrical supply. The completed Consolidation Study and associated Transmission Study illustrated a number of advantages in power supply arrangements and system planning that could be achieved through consolidation. In 1972, as a result of these studies and several years of planning and discussion, Central Power assumed ownership of over 500 miles of existing transmission line and 70 substation facilities located across the member's service area, along with the responsibility for planning and development of all future lines and stations. At that time, Central Power and its members also initiated the transfer of the generating plant at Velva to Basin Electric.

As member needs for power continued to grow, Central Power worked to build and strengthen this newly consolidated transmission system. Employing the benefits of "one-system" planning, Central Power transferred equipment and added lines and substations to its service area during the 1970's and into the 1980's in a system-wide program of expansion and updating. Financing for the major part of this activity was done through the Rural Utilities Service.

Today, Central Power operates with a facility consisting of 946 miles of transmission line, 117 distribution substations, 6 transmission switching stations, and 17 transmission step-down facilities. Together, these facilities form investment worth over $74 million, and generate revenues in excess of $48 million yearly. The cooperative employs 37 fulltime employees at its headquarters buildings located on the southern edge of the city of Minot, and retains the administrative, operational, and maintenance responsibilities for its facilities.

P.O. Box 196300
Anchorage, AK 99519-6300

Main Telephone (907) 563-7494
Main FAX (907) 562-0027
www.chugachelectric.com

Executive Contacts

Chief Executive Officer	*William R. Stewart*
Executive Assistant	*Connie Owens*
Chief Financial Officer	*Michael R. Cunningham*
Senior V.P. Power Delivery/Chief of Staff	*Lee D. Thibert*
Senior V.P. Power Supply	*Bradley W. Evans*

Accounting & Finance Related Personnel

Finance	*Michael R. Cunningham*
Corporate Budget	*Sherri McKay-Highers*
Accounting	*George "Jody" Wolfe*
Property Accounting	*Kathy Harris*
Insurance	*Amber VanTreeck*
Information Services	*David R. Smith-Director, Information Services*
Employee Benefits	*Mary Tesch-Vice President, Human Resources*

Ultimate Meters Served	208,213
REC Members	64,349
Other Firm Power Customers	3
Power Pool	No
Total Plant Capacity	530 MW
# of Substations	41
Miles of Transmission Line	533
Total Employees	348
Union Employees	247
RUS Designation	N/A

Taxable	No
State Regulated	Yes
Year Organized	1948
CPA - Tax	KPMG LLP
CPA - Audit	KPMG LLP
Corporate Insurance Providers	
Worker's Comp.	Liberty Mutual
Primary Liability	AEGIS
Comm. Umbrella	EIM
Electric Property	FM Global

2006 Financial Keys

Total Assets	$563,040,148
Total Operating Revenue	$267,542,713
Net Margins	$10,039,059
Equity Ratio	30.05%
T.I.E.R.	1.41
DSC Ratio	1.92
Cost of Debt	6.18%

MW Peak Demands

Winter	457
Summer	357

2006 MWH Sales

Member	1,523,289 @ $72.26 per MWH
Non-Mem	1,229,977 @ $125.65 per MWH

ORGANIZATION

Chugach Electric Association, Inc. (Chugach) organized as an Alaska not-for-profit electric cooperative in 1948, is the largest electric utility in Alaska. Chugach generates, transmits and distributes electricity to approximately 79,700 directly-served retail customers in the Anchorage and upper Kenai Peninsula area and through an interconnected regional electrical system to wholesale and economy customers throughout Alaska's Railbelt, a 400-mile long area stretching from the coastline of the southern Kenai Peninsula to the interior of the sate including Alaska's largest cities, Anchorage and Fairbanks.

MEMBERSHIP

On a regular basis, through its direct service to retail customers and indirectly through its wholesale and economy-energy sales, Chugach provides some or all of the electricity used by approximately 2/3 of Alaska's electric customers. Chugach also supplies much of the power requirements of 3 wholesale customers, Matanuska Electric Association (MEA), Homer Electric Association (Homer) and the City of Seward Electric System (SES). As of December 31, 2006, Chugach had approximately 64,349 of its own distribution members receiving power through approximately 79,700 installed meters. The business and affairs of Chugach are managed by the Chief Executive Officer and are overseen by its seven member Board of Directors. Directors are elected at large by the membership and serve three-year staggered terms.

POWER SUPPLY

Substantially all of Chugach's generating capacity is fueled by natural gas which Chugach purchases under long-term, relatively low-cost natural gas contracts. The remainder of Chugach's generating resources are hydroelectric facilities. The Chugach system includes 530 MW of installed generating capacity that is provided by 17 generating units at five different locations. During 2006, Chugach sold 2.75 billion kwh of power.

TRANSMISSION

Chugach owns 533 miles of transmission lines and 1,657 miles of distribution lines.

OTHER POINTS OF INTEREST

Chugach is unique among G&T's in that it has its own distribution system. In 1991, Chugach refinanced its federal debt by selling bonds in the public marketplace and forever left the RUS fold. Chugach's base load generation is natural gas fired and complemented by three hydro facilities. Chugach dispatches virtually all generation in the Alaska "Railbelt," the exception being Anchorage Municipal Light & Power generation resources. Chugach has paid capital credits to its retail side since 1986 (exception: none paid in 1995 and 2003) and to its wholesale members since 1993, currently rotating retail and wholesale on an approximately 15-year rotation cycle.

Corn Belt Power Cooperative

1300 13th St. N., P.O. Box 508
Humboldt, IA 50548

Main Telephone (515) 332-2571
Main FAX (515) 332-1375
www.chpower.coop

Executive Contacts

Executive Vice President & General Manager .... *Dale M. Arends*
Executive Assistant .... *Diane Wempen*
Vice President, Finance and Administration .... *Karen K. Berte*
Vice President, Engineering & System Operations .... *Kenneth H. Kuyper*
Vice President, Generation .... *Michael Thatcher*
Vice President, Corporate Relations .... *Kathy D. Taylor*
Vice President, Business Development .... *James Vermeer*

Accounting & Finance Related Personnel

Finance .... *Karen K. Berte*
Treasury .... *Karen K. Berte*
Accounting .... *Karen K. Berte*
Property Accounting .... *Kathy Saathoff - Property Accountant*
Tax Accounting .... *N/A*
Internal Auditing .... *N/A*
Insurance Plant .... *Karen K. Berte*
Data Processing .... *Tim Stetson*
Employee Benefits .... *Jennifer Arndorfer*

Ultimate Meters Served	37,706
REC Members	11
Other Firm Power Customers	1
Power Pool	MAPP
Total Plant Capacity	251 MW
# of Substations	142
Miles of Transmission Line	1,704
Total Employees	95
Union Employees	45
RUS Designation	IA 84

Taxable	No
State Regulated	No
Year Organized	1948
CPA - Tax	N/A
CPA - Audit	KPMG LLP
Corporate Insurance Providers	
Worker's Comp.	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	FM Global

2006 Financial Keys

Total Assets	$268,495,395
Total Operating Revenue	$73,951,474
Net Margins	538,602
Equity Ratio	14.79%
T.I.E.R.	1.07
DSC Ratio	1.15
Cost of Debt	5.06%

MW Peak Demands

Winter	254
Summer	261

2006 MWH Sales

Member ..... 1,560,557 @ $43.97 per MWH
Non-Mem ..... 46,253 @ $27.47 per MWH

Corn Belt Power Cooperative

ORGANIZATION

Two generation and transmission cooperatives (G&T's), Central Electric Federated Cooperative Association (Central) and Federated Cooperative Power Association (Federated), were both formed in 1937. In response to increased demand for power and efficiency, Central and Federated merged in 1947 to form Corn Belt Power Cooperative. Corn Belt is organized as an electric cooperative under section 501(c) (12) of the Internal Revenue Code.

MEMBERSHIP

Corn Belt serves eleven member distribution cooperatives and one municipal electric cooperative which serves twelve municipal electric utilities. The Corn Belt Board of Directors is composed of 10 distribution cooperative voting members and one voting member from the municipal electric cooperative. The Board sets policies and rates for the members.

POWER SUPPLY

Corn Belt wholly owns an older coal-fired generating plant and is part owner in two more coal-fired generating plants, one combustion turbine, and one nuclear-powered generating plant. In addition, Corn Belt has rights to hydro power from the Western Area Power Administration. Corn Belt is interconnected with 45 regional utilities through the Mid-Continent Area Power Pool (MAPP). Corn Belt maintains a system control center in Humboldt, Iowa but is dispatched by Mid American Energy Co.

TRANSMISSION

Corn Belt owns and maintains over 1,700 miles of high-voltage transmission line. Also owned and serviced by Corn Belt are 142 distribution substations and 24 microwave towers.

OTHER POINTS OF INTEREST

The two predecessor G&T's of Corn Belt were the first G&T's in the nation to receive RUS funds for electric generation. They received these funds in 1937 for the construction of the first G&T diesel generators. While the number of farmer consumers of our member distribution cooperatives has been declining over the last decade, Corn Belt has had an increase in industrial sales. Much of this increase can be attributed to success in industrial development efforts. With other Iowa G&T's and municipal utilities, Corn Belt jointly sponsors the Iowa Area Development Group, a statewide economic development organization. Corn Belt Power assists its member systems with site selection, financial packaging and industrial site development. The cooperative is a financial partner in business attraction, expansion projects and housing developments.

P.O. Box 817
La Crosse, WI 54602-0817

Main Telephone (608) 788-4000
Main FAX (608) 787-1420
www.dairynet.com

Executive Contacts

President & CEO	*William L. Berg*
Executive Assistant	*Laurie A. Engen*
Vice President, Finance & Administration	*Robert C. Mueller*
Vice President Generation	*Charles V. Sans Crainte*
Vice President, Transmission	*Chuck S. Callies*
Vice President, Human Resources	*Mary L. Lund*
Vice President, Strategic Planning	*Dale L. Pohlman*
Director, External Relations	*Brian D. Rude*

Accounting & Finance Related Personnel

Finance	*Keith W. Garrett - Director, Financial Mgmt.*
Treasury	*Keith W. Garrett*
Accounting	*Keith A. Stubbendick - Director, Accounting*
Property Accounting	*Susan Jolivette, Fixed Asset Mgmt.*
Tax Accounting	*Keith A. Stubbendick*
Insurance - Plant & Liability	*Daniel C. Fruehling - Risk Manager*
Data Processing	*Brian J. Boettcher - Director, Information Technology*
Employee Benefits	*A. J. Leisso - Manager, Employee Benefits*
Resource Planning	*John M. McWilliams - Resource Planning*

Ultimate Meters Served	244,726
REC Members	25
Other Firm Power Customers	20
Power Pool	MAPP
Total Plant Capacity	1,110 MW
# of Substations	294
Miles of Transmission Line	3,111
Total Employees	598
Union Employees	288
RUS Designation	WI 64

Taxable	No
State Regulated	No
Year Organized	1941
CPA - Tax	N/A
CPA - Audit	Deloitte & Touche
Corporate Insurance Providers	
Worker's Comp.	AIG
Primary Liability	AIG
Commercial Umbrella	AEGIS
Electric Property	HSB/Starrdech

2006 Financial Keys

Total Assets	$945,788,755
Total Operating Revenue	$284,439,111
Net Margins	$11,438,988
Equity Ratio	12.46%
T.I.E.R.	1.51
DSC Ratio	1.16
Cost of Debt	4.42%

MW Peak Demands

Winter	916
Summer	1,003

2006 MWH Sales

Members	5,463,467 @ $46.37 per MWH
Non-Mem	655,184 @ $33.77 per MWH

ORGANIZATION

Dairyland Power Cooperative, La Crosse, Wisconsin, provides the wholesale electrical requirements and other services for 25 rural electric distribution cooperatives and 20 municipal utilities which supply the energy needs for nearly half a million people.

Dairyland's Board of Directors is comprised of an elected member from each Class A membership cooperatives' board, and one representative for its Class B members. The Dairyland Association of Managers provides additional input on operations for management consideration.

FINANCIAL/RATES

Dairyland is a non-profit cooperative, not subject to federal taxes. Its wholesale rates are subject to RUS approval. None of the Dairyland system distribution cooperatives are subject to state regulation.

Dairyland's 2006 TIER was 1.51, while the DSC ratio was 1.16. Its financial ratings are A by Standard and Poor's, and A2 by Moody's.

OPERATIONS

Dairyland operates one hydro, three combustion turbine, and three coal-fired generating stations with 1110 megawatts of capacity. The electricity produced is transmitted via 3,111 miles of transmission lines to 294 substations located through the system's 44,500 square mile service area. This service area encompasses 62 counties in four states (Wisconsin, Minnesota, Iowa, and Illinois)

Dairyland is a charter member of the Mid-Continent Area Power Pool (MAPP). Support pledged by the other members of the power pool provides insurance to Dairyland members in the event of an emergency. Through this marketplace, Dairyland may take advantage of opportunities to buy and sell energy to lower its costs and improve efficiency.

In 2006, Dairyland sold 6,118,651 MWh, of which 4,198,531 or 69% was to Class A members for revenue of $218,099,596. Dairyland generated 94% of its energy available for sale.

Deseret G&T Cooperative

10714 S. Jordan Gateway
South Jordan, UT 84095

Main Telephone (801) 619-6500
Main FAX (801) 619-6599
www.deseretgt.com

Executive Contacts

President	*Kimball Rasmussen*
Executive Assistant	*Debra Horrocks*
Senior Vice President, CFO	*Soren K. Sorensen*
Vice President, Chief Engineer	*Ed Thatcher*
Vice President, Marketing	*Curtis Winterfeld*
Vice President, General Counsel	*Dave Crabtree*
Controller	*Dave Carroll*
Plant Manager	*Stan Gordon*
Transmission, Substations & Communication Division Manager	*I. 'Dee Curtis*
Human Resources Director	*Rose Milne*

Accounting & Finance Related Personnel

Finance	*Soren K. Sorensen*
Accounting	*Dave Carroll*
Coal Mine & Railroad Accounting	*Frank Crowther*
Tax Accounting	*Kate Wright*
Internal Auditing	*Greg Humphreys*
Insurance - Plant	*Soren K. Sorensen*
Data Processing	*David Westfall*
Cash Management	*Brent Taylor*
Resource Planning	*Curt Winterfeld*

Ultimate Meters Served	52,680
REC Members	6
Other Firm Power Customers	11
Power Pool	N/A
Total Plant Capacity	550 MW
# of Substations	5
Miles of Transmission Line	270
Total Employees	141
Union Employees	0
RUS Designation	UT 21

Taxable	Yes
State Regulated	No
Year Organized	1978
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Deloitte & Touche LLP

Corporate Insurance Providers

Worker's Comp	Chubb
Primary Liability	AEGIS
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$474,944,836
Total Operating Revenue	$218,755,725
Net Margins	$10,829,905
Equity Ratio	20.42%
T.I.E.R.	1.33
DSC Ratio	1.10
Cost of Debt	10.63%

MW Peak Demands

Winter	702
Summer	726

2006 MWH Sales

Member	2,075,361 @ $38.92 per MWH
Non-Mem	3,500,350 @ $40.05 per MWH

ORGANIZATION

Deseret Generation & Transmission Cooperative was formed by its six members in May 1978, to provide increased firm power supplies on a coordinated basis. It commenced operations in October 1980, when Deseret acquired a 39.69% undivided interest in the Hunter Unit No. 11, a 395 (net) MW, coal-fired generating unit from Utah Power & Light. In July 1983, Deseret began construction of the Bonanza Unit No. 1 a 420 (net) MW, coal-fired generating unit in Northeastern Utah. The Bonanza Power Station was placed into commercial operations in May 1986. Coal for the Bonanza Power Station is supplied from Deseret's subsidiary Blue Mountain Energy's Deserado coal mine, which is located in Colorado. A 35-mile electrified railroad was constructed to deliver the coal from the mine to the power plant. Deseret financed the construction of the Bonanza Power Station and the development and construction costs of the Deserado mine by borrowings from the Federal Finance Bank, (FFB) and by issuing pollution control bonds. In October 1996, CFC and Deseret's members purchased Deseret's RUS debt. In 1996, Deseret acquired Blue Mountain Energy (previously known as Western Fuels - Utah) which supplies all of the coal to the Bonanza Plant. In December 1998, Deseret entered into a recapitalization and settlement agreement which settled all outstanding issues related to Deseret's debt restructure.

MEMBERSHIP

Deseret's Board of Trustees consists of two representatives from each of its six Rural Electric Cooperative members (Members).

The six Members all serve different rural areas in Utah along with some service areas in Colorado, Wyoming, Arizona and Nevada. As of December 31, 2001 the Members owned approximately 9,347 miles of transmission and distribution lines (7.2 kv to 138 kv). The Members also owned 75 transmission and distribution substations with a total capacity of 555,258 KVA. Deseret also owns approximately 100 miles of 138 kv and 170 miles of 345 kv lines.

OTHER POINTS OF INTEREST

Deseret was incorporated under the Non-profit Corporation and Cooperative Association Act of the State of Utah. In 1982, Deseret received an Internal Revenue Service ruling that it is a taxable Cooperative. Accordingly, Deseret is entitled to exclude the amount of patronage allocations to members from gross income. Income and expenses related to nonmember operations are taxable to Deseret.

In December 1999, Deseret moved into their new headquarters building. Deseret was able to pay cash for the 30,000 square foot three story building.

In November 2002, the Bonanza Power station was cited by Power Magazine as 2001's most dependable coal-fired power plant in the U.S. The industry's technical term is "capacity factor" and Bonanza achieved 97.66%. By comparison the U.S. national average is 66.63% only seven power stations enjoyed capacity factors in the 90% plus range.

P.O. Box 707
Winchester, KY 40392-0707

Main Telephone (859) 744-4812
Main FAX (859) 744-6008
www.ekpc.coop

Executive Contacts

President/Chief Executive Officer	*Robert M. Marshall*
Executive Secretary	*Claudia H. Embs*
Chief Financial Officer	*David G. Eames*
Senior Vice President, G&T Operation	*John Twitchell*
General Counsel	*David Smart*
Vice President, Human Resources & Support Services	*Doug Oliver*
Vice President, Member Services	*Gary Crawford*
Senior Vice President, Power Supply	*Jim Lamb*

Accounting & Finance Related Personnel

Finance	*Frank Oliva, Manager*
Treasury	*Frank Oliva*
Accounting	*Ann Wood - Manager, Accounting & Materials Mgt.*
Property Accounting	*Ann Wood*
Tax Accounting	*Ann Wood*
Insurance Plant	*Frank Oliva*
Data Processing	*Wes Moody - Manager, Information Technology*
Employee Benefits	*Steve McClure - Manager, Human Resources & Support Services*
Internal Audit	*Graham Johns*

Ultimate Meters Served	504,492	Taxable	No
REC Members	16	State Regulated	Yes
Other Firm Power Customers	0	Year Organized	1941
Power Pool	N/A	CPA - Tax	N/A
Total Plant Capacity	2,296 MW	CPA-Audit	Crowe Chizek & Company LLC
# of Substations	402	**Corporate Insurance Providers**	
Miles of Transmission Line	2,673	Excess Worker's Comp	AEGIS
Total Employees	655	Primary Liability	Self-Insured
Union Employees	N/A	Commercial Umbrella	AEGIS
RUS Designation	KY 59	Electric Property	FM Global

2006 Financial Keys

Total Assets	$2,028,501,182
Total Operating Revenue	$650,959,941
Net Margin	$11,173,989
Equity Ratio	5.28%
T.I.E.R.	1.13
DSC Ratio	0.98
Cost of Debt	5.43%

MW Peak Demands

Winter	2,859
Summer	2,339

2006 MWH Sales

Member	12,129,402 @ $53.22 per MWH
Non-Mem	77,010 @ $44.90 per MWH

ORGANIZATION

East Kentucky Power Cooperative was formed in 1941 as East Kentucky Rural Electric Cooperative Corporation. When World War II broke out, plans for the system were voluntarily suspended. In 1951, planning was resumed and East Kentucky opened its offices in Winchester, Kentucky. Its first generating station, the William C. Dale Station, was completed in 1954. East Kentucky is fully regulated by the Kentucky Public Service Commission.

MEMBERSHIP

East Kentucky's Board of Directors is made up of one director and one alternate director from each of its sixteen member distribution cooperatives. This board sets overall operating policies for the cooperative. East Kentucky's sixteen member distribution cooperatives serve member/consumers throughout the eastern two-thirds of Kentucky.

POWER SUPPLY

Construction began in 1951 on East Kentucky's first generating station, the William C. Dale Station. The first two units were completed in 1954. The third unit was completed in 1957 and the fourth unit in 1960. Dale Station, with 196 megawatts of net capacity, continues to supply power to the East Kentucky system. In 1965, the first of two units at the John Sherman Cooper Station was completed.

The second unit, completed in 1969, increased the total capacity of the Cooper Station to 341 megawatts. In 1977, Unit 1 of the H.L. Spurlock Station was completed and Unit 2 was added in 1981. A third unit began commercial operation on March 1, 2005. The total capacity of the Spurlock Station is 1,118 megawatts. In addition to this 1,655 megawatts of its own net generating capacity, East Kentucky has access to 170 megawatts of hydro generation from the Southeastern Power Administration.

East Kentucky has added seven gas-fired combustion turbines to provide peaking capacity. The combustion turbines will have a total nominal summer rating of 626 MW.

TRANSMISSION

At the end of 2006, East Kentucky Power had 2,673 miles of transmission line ranging in size from 34.5 kV to 345 kV. These lines provide service to 322 distribution substations and 80 transmission substations.

OTHER POINTS OF INTEREST

East Kentucky Power (EKP) is the only member of Charleston Bottoms Rural Electric Cooperative Corporation (CB). CB, the owner of Unit 1 of the H.L. Spurlock Generating Station, was formed for the purpose of providing a financing mechanism for the construction of this generating unit. EKP operates and maintains Spurlock Unit 1 and takes all of the output of the unit. East Kentucky has five landfill gas facilities with a total capacity of 15 MW.

East River Electric Power Cooperative, Inc.

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Madison, SD 57042

Main Telephone (605) 256-4536
Main FAX (605) 256-8058
www.eastriver.coop

Executive Contacts

General Manager .... *Jeffrey Nelson*
Assistant General Manager - Administration .... *Greg Hollister*
Assistant General Manager - Operations .... *Jim Edwards*
Assistant General Manager - Member Services .... *Scott Parsley*
General Counsel .... *Bob Sahr*

Accounting & Finance Related Personnel

Finance and Treasury .... *Randy Hoffman - Budgeting Services Manager*
General and Property Accounting ...... *Barb Strom - Finance & Accounting Manager*
Tax Accounting .... *N/A*
Internal Auditing .... *N/A*
Insurance Plant .... *Barb Strom*
Data Processing .... *Chuck Lohsandt - Information Technology Analysis*
Employee Benefits .... *Valerie Manthey - Human Resources Coordinator*
Resource Planning .... *Greg Hollister*

Ultimate Meters Served	93,000
REC Members	20
Other Firm Power Customers	1
Power Pool	N/A
Total Plant Capacity	1,556 MW
# of Substations	218
Miles of Transmission Line	2,588
Total Employees	104
Union Employees	N/A
RUS Designation	SD 43

Taxable	No
State Regulated	No
Year Organized	1949
CPA - Tax	Eide Bailley, LLP
CPA - Audit	Eide Bailley, LLP
Corporate Insurance Providers	
Worker's Comp.	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$181,601,804
Total Operating Revenue	$85,727,358
Net Margins	$5,975,143
Equity Ratio	34.33%
T.I.E.R.	2.32
DSC Ratio	1.49
Cost of Debt	4.78%

MW Peak Demands

Winter	405
Summer	396

2006 MWH Sales

Member	2,408,994 @ $32.67 per MWH
Non-Mem	0

East River Electric Power Cooperative

ORGANIZATION

East River Electric Power Cooperative was organized in 1949 by 21 electric distribution cooperatives in eastern South Dakota and western Minnesota. East River's purpose was to build and operate the transmission lines and substations to provide wholesale power to these distribution cooperatives.

MEMBERSHIP

Today, East River provides wholesale power transmission service to 21 member distribution systems including 20 electric distribution cooperative systems and one municipal electric system, the City of Elk Point, South Dakota. These member systems, in turn, supply retail electric service to over 93,000 service accounts and 250,000 people. East River's Board of Directors consists of one director from each of its member systems. This Board meets monthly and sets policy and wholesale electric rates for its members.

POWER SUPPLY

Currently, East River receives approximately 30% of its power requirements from the Western Area Power Administration which markets the federal hydropower in the upper midwest region. The remaining 70% of East River's power purchases are from Basin Electric Power Cooperative's coal-fired generating plants located in North Dakota and Wyoming.

TRANSMISSION

East River operates and maintains 2,588 miles of high voltage transmission line, 218 substations and related facilities to serve an area of 36,000 square miles.

East River also operates a 24 hour dispatch and control center, a microwave and SCADA communication system, a load management system, a 800MHz trunked radio system, and a voltage regulator maintenance facility for PCB contaminated oil. The Cooperative also has seven maintenance outpost crews and facilities to serve its members. The East River load management system covers the largest geographic area of any similar installation in the United States. More than 72,000 electric devices including water heaters , heating and air conditioning systems, irrigation and crop drying systems are connected to the load management system. Use of the load management system enables distribution cooperative members to use electricity at reduced off-peak rates and has helped East River avoid more than $93 million in additional wholesale power costs since January, 1985.

OTHER POINTS OF INTEREST

East River has more than $161 million invested in transmission facilities in eastern South Dakota and western Minnesota. The Cooperative has annual revenues of more than $85 million and pays $1.7 million annually in taxes to support local, state and federal purposes. More that $15 million in non-profit earnings have been returned to member systems. East River uses excess capacity in its transmission system to deliver wholesale power to 25 municipal electric systems and other customers in South Dakota, Minnesota and Iowa.

Georgia Transmission Corporation

P.O. Box 2088
Tucker, GA 30085-2088

Main Telephone (770) 270-7400
Main FAX (770) 270-7872

Executive Contacts

President and Chief Executive Officer	*Mike Smith*
Sr. Executive Staff Assistant to CEO	*Nina McNieve*
Sr. Vice President & Chief Financial Officer	*Barbara Hampton*
Sr. Vice President, Project Services	*Jerry Donovan*
Vice President, System Planning	*Russ Schussler*
Vice President, System Performance	*Harold Taylor*
Vice President Transmission Policy	*Keith Daniel*
Vice President External Affairs & Member Relations	*Tom Parker*
Vice President, Operations and Maintenance	*David Van Winkle*

Accounting & Finance Related Personnel

Controller	*Lynn Huffines*
General Accounting	*Duane Jeffries*
Property Accounting	*Cornell Casey*
Tax Accounting	*Dale Cooper*
Internal Auditing	*Angela Sheffield*
Information Techonology (provided by GSOC)	*Gary Williamson*
Insurance-Plant (provided by GSOC)	*Dolores Anderson*
Employee Benefits (provided by GSOC)	*Homer Gentry*
Board Administration (provided by GSOC)	*Patty Nash*

Ultimate Meters Served	1,487,369
REC Members	40
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	N/A
# of Substations	590
Miles of Transmission Line	2,760
Total Employees	237
Union Employees	0
RUS Designation	GA 110

Taxable	No
State Regulated	No
Year Organized	1996
CPA - Tax	McGladrey & Pullen
CPA - Audit	McGladrey & Pullen

Corporate Insurance Providers

Worker's Comp.	State Fund
Primary Liability	Federated.
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$1,355,325,000
Total Operating Revenue	$193,436,000
Net Margins	$11,085,000
Equity Ratio	9.77%
Margins for Interest	1.194
DSC Ratio	
Cost of Debt	5.1377%

MW Peak Demands

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	N/A
Non-Mem	N/A

Georgia Transmission Corporation

ORGANIZATION

Georgia Transmission Corporation (An Electric Membership Corporation)) ("GTC") is a Georgia electric membership corporation incorporated in 1996, and is headquartered in Atlanta, Georgia. Oglethorpe Power Corporation and its members completed a corporate restructuring on March 11, 1997. Pursuant to the corporate restructuring, Oglethorpe divided itself into three specialized operating companies to respond to increasing competition and regulatory changes in the electric industry. As part of the corporate restructuring, GTC purchased and now owns the transmission assets and operates the transmission business previously owned and operated by Oglethorpe.

MEMBERSHIP

GTC is entirely owned by its 39 retail electric distribution cooperative members (the "Members") who are entirely owned by their retail consumers. Oglethorpe is also a member of GTC. GTC is governed by a thirteen Member Board of Directors, including eleven directors elected from the Members and two independent outside directors.

TRANSMISSION AGREEMENTS

GTC and the Members have entered into Member Transmission Service Agreements (the "Transmission Agreements") under which GTC provides transmission service to the Members. The Transmission Agreements have a minimum term of network service for current load until December 31, 2040. The Transmission Agreements provide that if a Member elects to purchase a part of its network service elsewhere, it must pay appropriate stranded costs to protect the other Members from any rate increase that could otherwise occur. Under the Transmission Agreements, Members have the right to design, construct, and own new distribution substations, and GTC will be responsible for the operation of the designated transmission portion of such facilities.

The Transmission Agreements provide that the Members are responsible, on a joint and several basis, for all of GTC's obligations relating to its transmission business. The Transmission Agreements contain an express covenant of the Members to set and collect retail rates sufficient for the Members to meet their respective obligations under the Transmission Agreements. The rate formula set in the transmission tariff is intended to recover all of GTC's costs and expenses paid or incurred. The rate expressly includes in the description of costs to be recovered, all principal and interest on indebtedness of GTC. The rate further expressly provides for GTC to earn sufficient margins to satisfy the requirements of its indenture.

As of December 31, 2006, GTC owned approximately 2,826 miles of transmission line and approximately 600 substations of various voltages. GTC provides power and energy to the Members through the Integrated Transmission System ("ITS") consisting of transmission system facilities co-owned by GTC, Georgia Power Company, MEAG Power, and Dalton Utilities. As a result of its participation in the ITS, GTC is entitled to use any of the transmission facilities included in the system, regardless of ownership.

OTHER POINTS OF INTEREST

Beginning in 2002, support services functions were provided through a business alliance with Georgia System Operations Corporation (GSOC). The following functions were performed by GSOC personnel: payroll, accounts payable, auditing, employee benefits, facility management, telecommunications and information technology.

GTC is a tax-exempt cooperative.

FINANCIAL RATINGS INFORMATION

Standard & Poor's........AA-
Moody's (Senior Secured)........A3
Fitch.........AA-

P.O. Box 9898
Amarillo, TX 79105-5898

Main Telephone (806) 379-7766
Main FAX (806) 374-2922

Executive Contacts

President & General Manager	*Robert W. Bryant*
Vice President, Transmission & Operations	*Mike Wise*
Vice President, Finance & Accounting	*Melody Gillis*
Manager, Accounting Services	*Steven Wiegand*
Manager, Generation	*Randy Allison*
Manager, Engineering	*Shane McMinn*
Accountant	*Chesna Foster*
Executive Assistant	*Janis Weems*

Ultimate Meters Served	202,000
REC Members	16
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	N/A
# of Substations	N/A
Miles of Transmission Line	119
Total Employees	10
Union Employees	N/A
RUS Designation	TX 159

Taxable	No
State Regulated	Yes
Year Organized	1984
CPA - Tax	Clifton Gunderson PLLC
CPA - Audit	Bolinger, Segars, et al.

Corporate Insurance Providers

Worker's Comp.	Texas Mutual Ins. Co.
Primary Liability	Illinois National Insurance Company (AIG)
Commercial Umbrella	Various

2006 Financial Keys

Total Assets	$341,107,480
Total Operating Revenue	$436,106,124
Net Margins	$25,171,157
Equity Ratio	37.05%
T.I.E.R.	3.55
DSC Ratio	2.65
Cost of Debt	6.28%

MW Peak Demands

Winter	561
Summer	1,222

2006 MWH Sales

Member .....4,923,961 @ $69.44 per MWH
Non-Mem.. 1,553,790 @ $59.61 per MWH

ORGANIZATION

Golden Spread Electric Cooperative, Inc., with headquarters in Amarillo, Texas, is a tax-exempt, consumer-owned public utility, organized in 1984 to provide low cost, reliable electric service for its rural distribution cooperative members. GS Electric Generating Cooperative, Inc. (GSEGC) is a wholly owned affiliate, engaging in exempt wholesale generating (EWG) activities. Yoakum Electric Generating Cooperative, Inc. (YEGC), a wholly-owned affiliated EWG, was formed by Golden Spread in 2005 for the purpose of owning two simple cycle generating facilities. One of these facilities (Mustang Station Unit 4) achieved commercial operation in 2006 and the other (Mustang Station Unit 5) is currently under construction and is expected to achieve commercial operation in spring 2007.

MEMBERSHIP

Golden Spread has 16 rural electric member systems, which supply power to approximately 202,000 member-consumers. Fifteen member cooperatives are located in the Panhandle, South Plains and the Edwards Plateau regions of Texas and one is located in the Panhandle of Oklahoma. Golden Spread has members located in both the Southwest Power Pool (SPP) and ERCOT regions. Thirty-two directors make up the Golden Spread Board, with each member system represented on the Board by its general manager and a member of its board of directors/trustees.

GENERATION

Through Golden Spread's affiliate, GSEGC, Golden Spread owns a 50% interest in Mustang Station, a 480 MW gas-fueled combined cycle generating plant. Mustang Station began full commercial operation in April 2000. In 2006 Golden Spread completed construction of a 150 MW (summer rating) simple cycle gas-fired generating facility (Mustang Station Unit 4) adjacent to the existing Mustang Station. The facility achieved commercial operation in the spring of 2006. Mustang Station Unit 5, a 150 MW (summer rating) simple cycle gas-fired generating facility, is currently under construction and is expected to achieve commercial operation in spring 2007. This facility is also adjacent to the existing Mustang Station.

POWER SUPPLY RESOURCES

Golden Spread purchases its requirements for its 16 member systems from five power suppliers: (1) Golden Spread buys all of the 480 MW Mustang Station capacity, of which one-half is purchased from GSEGC, and (2) one-half is purchased under a separate supply contract with Denver City Energy Associates, L.P., Mustang Station's co-owner; (3) a partial requirements agreement with Southwestern Public Service Company (SPS), an Xcel Energy, Inc. subsidiary, which provides 370 MW (430 MW beginning June 1, 2006) of partial requirements service. The remaining two suppliers, AEP and TXU, provide all - requirements service primarily in the ERCOT region. Golden Spread's wholesale power contracts afford its members exceptional flexibility in decisions concerning future power supplies while providing appropriate security for investments made by Golden Spread and its affiliates.

TRANSMISSION

Golden Spread delivers power and energy to its member systems under network integrated transmission service agreements with SPS and SPP. ERCOT provides transmission service to all loads within ERCOT in accordance with the substantive rules of the PUCT and market protocols and operating guides of ERCOT. Golden Spread owns certain transmission properties on behalf of two members under Special Facilities Agreements whereby the costs of such properties are directly assigned and fully recoverable from the respective members under a tariff specifically designed for such purposes.

REGULATION

Golden Spread is subject to the jurisdiction of the FERC for corporate and rate regulation related to its activities in the SPP, and is subject to the regulation of the PUCT for certain activities in both ERCOT and SPP. GSEGC and YEGC are, and OEGC will be, subject to regulation as exempt wholesale generators at FERC, and subject to certain reporting requirements at the PUCT.

FINANCIAL REPORTING

Golden Spread prepares consolidated financial statements including the accounts of Golden Spread and its wholly owned affiliates. The accounting records are maintained in accordance with the Uniform System of Accounts as prescribed by the FERC.

OTHER POINTS OF INTEREST

Substantial excess energy from Mustang Station is available off-peak and Golden Spread has a Commitment & Dispatch Agreement (C&D) with SPS whereby SPS purchases such energy on a "split the savings" basis. The margins from these sales comprise a significant part of the net margins of Golden Spread, having contributed over $93 million in margins over the last seven years.

FINANCIAL RATINGS INFORMATION

In 2004, Golden Spread engaged Fitch Ratings, Inc. to perform a credit review. The rating was issued in February 2005, with Golden Spread receiving an A- credit rating, which was reaffirmed in 2006.

P.O. Box 800
Elk River, MN 55330-0800

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Main FAX (763) 241-2366
www.greatriverenergy.com

Executive Contacts

President & Chief Executive Officer	*David Saggau*
Manager, Executive Services	*Louy Theeuwen*
Vice President & Chief Financial Officer	*Larry Schmid*
Vice President, Transmission	*Will Kaul*
Vice President, Member Services	*Jon Brekke*
Vice President, Generation	*Rick Lancaster*
Vice President, Communications and Human Resources	*Kandace Olsen*
Vice President and General Counsel	*Eric Olsen*
Vice President and Chief Information Officer	*Jim Jones*
Vice President, Business Development & Strategy	*Greg Ridderbusch*

Accounting & Finance Related Personnel

Finance	*Susan Brooks, Manager of Finance*
Treasury	*Susan Brooks*
Accounting	*Doug Paumen - Manager, Accounting Services*
Tax Accounting	*Ron Grossinger - Sr. Accounting Analyst*
Property Accounting	*Ron Grossinger*
Internal Auditing	*Jim Ingman - Sr. Financial Analyst*
Insurance Plant	*Susan Brooks*
Employee Benefits	*Rhonda Keyser Rusch - Manager, Compensation & Benefits*
Resource Planning	*Glen Skarbakka - Manager, Resource Planning*

Ultimate Meters Served	626,545
REC Members	28
Other Firm Power Customers	5
Power Pool	MAPP
Total Plant Capacity	2,600 MW
# of Substations	102
Miles of Transmission Line	4,583
Total Employees	768
Union Employees	221
RUS Designation	MN 110

Taxable	Yes
State Regulated	No
Year Organized	1998
CPA - Tax	Deloitte & Touche, LLP
CPA - Audit	Deloitte & Touche, LLP
Corporate Insurance Providers	
Worker's Comp	Self-Insured
Primary Liability	Federated
Commercial Umbrella	AEGIS & EIM
Electric Property	FM Global

2006 Financial Keys

Total Assets	$1,980,916,000
Total Operating Revenue	$710,031,000
Net Margins	$55,962,773
Equity Ratio	11.85%
T.I.E.R.	1.83
DSC Ratio	1.28
Cost of Debt	5.45%

MW Peak Demands

Winter	2,128
Summer	2,563

2006 MWH Sales

Member	11,421,473 @ $44.52 per MWH
Non-Mem	3,243,972 @ $54.75 per MWH

ORGANIZATION

Great River Energy (GRE) is a generation and transmission cooperative based in Elk River, Minnesota, that provides electricity to 28 member distribution cooperatives throughout Minnesota and a portion of western Wisconsin. GRE was formed on January 1, 1999 through the consolidation of operations of Cooperative Power (CP) and United Power Association (UPA).

POWER SUPPLY

GRE currently has three baseload generating facilities; two in North Dakota (Coal Creek Station—1,114 megawatts and Stanton Station—188 megawatts) and one at the cooperative's headquarters in Minnesota (Elk River Station—39 megawatts). Lignite is the fuel for Coal Creek Station, Powder River Basin coal is the fuel for Stanton Station, while Elk River Station uses refuse derived fuel, a fuel made from municipal solid waste.

GRE has a life-of-plant agreement with Dairyland Power Cooperative to share in half of the output of the Genoa-3 coal-fired power plant near LaCrosse, Wisconsin. Several of GRE's members have long-term power supply contracts with WAPA.

GRE currently has six peaking stations: Lakefield Junction Station in Martin County, Minnesota, has a generating capacity of 515 megawatts; Pleasant Valley Station, located in Mower County, Minnesota, has a generating capacity of 424 megawatts; and four other peaking plants with a total capability of 113 megawatts. GRE continues to review its power supply needs and will need additional energy and capacity over the next ten years.

GRE completed construction of a 170-MW natural gas-fueled combustion turbine at the site of its existing peaking plant in Cambridge, Minnesota in April 2007. This peaking plant, Cambridge Station, will be used by GRE to meet system peak demands beginning in the summer of 2007.

TRANSMISSION

GRE operates approximately 4,554 miles of transmission line with voltages ranging from 69 kV to 500 kV alternating current. GRE also operates a 435 mile high voltage (+400 kV) direct-current line that provides the essential link between Coal Creek Station and GRE's Minnesota transmission network.

In addition to its own transmission systems, GRE has interconnection agreements with neighboring utilities.

OTHER POINTS OF INTERESTS

GRE is Minnesota's second largest electric utility in terms of generating capacity.

GRE has an A- credit rating from Fitch Ratings and a BBB credit rating from Standard and Poors.

P.O. Box 908
Bloomington, IN 47402

Main Telephone (812) 876-2021
Main FAX (812) 876-3476
www.hepn.com

Executive Contacts

President & CEO	*J. Steven Smith*
Executive Secretary	*Melanie Turner*
Interim Vice President, Power Production	*Robert Richhart*
Sr. Vice President, and Chief Financial Officer	*Thomas L. Bernardi*
Sr. Vice President, Marketing and Business Development	*Mike Rampley*
Vice President, Management Services	*Robert Richhart*
Vice President, Finance and Controller	*Donna Snyder*
Vice President, Power Supply	*David Sandefur*
Director of Public Affairs	*Randy Haymaker*

Accounting & Finance Related Personnel

Finance	*Thomas L. Bernardi*
Treasury	*Donna Snyder*
General Accounting	*Fredna Holmgren - Assistant Controller*
Property Accounting	*Fredna Holmgren*
Tax Accounting	*Donna Snyder*
Internal Auditing	*Tina Bex, Sr. Analyst & Internal Control Specialist*
Corporate Property & Liability Ins	*Bob Hill - Mgr., Generation Investment & Control*
Data Processing	*Lance Davis - Manager, Information Systems*
Employee Benefits	*Roger Owens - Mgr.. Human Resources & Labor Relations*
Resource Planning	*Mike Mooney, Manager, Corporate Planning*

Ultimate Meters Served	276,742
REC Members	17
Other Firm Power Customers	3
Power Pool	RFC, Midwest ISO
Total Plant Capacity	1,670 MW
# of Substations	237
Miles of Transmission Line	1,400
Total Employees	463
Union Employees	275
RUS Designation	IN 106

Taxable	Yes
State Regulated	No
Year Organized	1949
CPA - Tax	Pricewaterhouse Coopers LLP
CPA - Audit	Deloitte & Touche

Corporate Insurance Providers

Worker's Comp	New Hampshire
Primary Liability	American Home Assur.
Commercial Umbrella	Arch Specialty
Electric Property	Factory Mutual

2006 Financial Keys

Total Assets	$1,042,444,450
Total Operating Revenue	$441,344,744
Net Margins	$8,535,671
Equity Ratio	11.36%
T.I.E.R.	1.20
DSC Ratio	1.3
Cost of Debt	5.30%

MW Peak Demands

Winter	1,298
Summer	1,366

2006 MWH Sales

Member	6,525,739 @ $49.00 per MWH
Non-Mem	3,397,819 @ $34.00 per MWH

ORGANIZATION

Hoosier Energy Rural Electric Cooperative was formed by nine rural electric distribution systems in 1949 to negotiate bulk power purchases at the lowest possible costs and favorable terms. Today, Hoosier Energy generates, transmits, and sells electricity at wholesale rates to its members - 17 rural electric cooperatives in central and southern Indiana. These cooperatives distribute electricity to an estimated 650,000 residents, businesses, industries and farms. Effective January 14, 1998, Hoosier Energy withdrew from Indiana Utility Regulatory Commission regulation to obtain more flexibility to support member systems. Effective with the withdrawal, the Board of Directors became Hoosier Energy's primary rate making and regulatory body.

MEMBERSHIP

Hoosier Energy's Board of Directors consists of one representative from each of its 17 member distribution systems. The Board develops policies and reviews the cooperative's operations. Day-to-day management of Hoosier Energy is carried out by the president and chief executive officer and his staff, supervising some 463 employees.

POWER SUPPLY

By producing their own electricity through two coal-fired generating facilities, Hoosier Energy member systems achieve substantial power cost savings. Commercial operation of Hoosier Energy's first power plant, the coal-fired 250 MW Ratts Generating Station, began in 1970. To continue providing member systems a dependable power supply at the lowest cost possible, Hoosier Energy built the 1,070 MW Merom Generating Station in the 1980's. The Merom Station provides nearly 75% of the cooperative's power supply needs. The coal-fired plant uses Indiana coal, and is equipped with sulfur dioxide-removing scrubbers and selective catalytic reduction technology that allow the plant to comply with new environmental regulations. Hoosier Energy also owns approximately 350 MW of gas-fired peaking capacity.

POWER REQUIREMENTS

In addition to providing competitively priced and reliable wholesale power to its members, Hoosier sells wholesale power to non-members under various power sales agreements, which expire starting in 2007 through 2017.

TRANSMISSION

Hoosier Energy owns and operates over 1,400 miles of transmission lines, 14 primary substations and over 200 distribution substations and delivery points. Interconnections link Hoosier Energy with seven other major utilities in Indiana and neighboring states, assuring a reliable power source for member systems. Hoosier Energy member systems encompass a 15,000 square mile service area in central and southern Indiana.

KAMO Electric Cooperative, Inc.

P.O. Box 577
Vinita, OK 74301-0577

Main Telephone (918) 256-5551
Main FAX (918) 256-8023
www.kamopower.com

Executive Contacts

Executive Vice President & CEO	*J. Chris Cariker*
CEO Assistant	*Cindy Allen*
Chief Operations Officer	*Ted Hilmes*
Chief Technology Officer	*Walt Kenyon*
Chief Financial Officer	*Ann Hartness*
Director, Operations & Substation Maintenance	*Keith Harrison*
Director, Human Resources	*Shirley McDaniel*
Director, Construction	*Tommy Hayes*

Accounting & Finance Related Personnel

Finance	*Ann Hartness*
Treasury	*Shari Fenstermacher*
General Accounting	*Janis Heltzen*
Property Accounting	*Shari Fenstermacher*
Tax Accounting	*Ann Hartness*
Corporate Property & Liability Insurance	*Terry Brown*
Data Processing	*Ann Hartness*

Ultimate Meters Served	319,000
REC Members	18
Other Firm Power Customers	0
Power Pool	AECI & GRDA
Total Plant Capacity	200 MW
# of Substations	225
Miles of Transmission Line	2,082
Total Employees	116
Union Employees	0
RUS Designation	ARK 32

Taxable	No
State Regulated	No
Year Organized	1941
CPA - Tax	BKD
CPA - Audit	BKD
Corporate Insurance Providers	
Worker's Comp.	Self-Insured Pool
Primary Liability	AIG
Commercial Umbrella	AEGIS
Electric Property	AIG

2006 Financial Keys

Total Assets	$404,848,990
Total Operating Revenue	$226,746,915
Net Margins	$5,387,080
Equity Ratio	26.55%
T.I.E.R.	1.36
DSC Ratio	1.34
Cost of Debt	6.81%

MW Peak Demands

Winter	1,311
Summer	1,459

2006 MWH Sales

Member	5,860,754 @ $38.31 per MWH
Non-Member	0

ORGANIZATION

KAMO Electric Cooperative, Inc. (some times referred to as KAMO or KAMO Power) was formed on April 15, 1941, by 12 distribution cooperatives from Kansas, Arkansas, Missouri and Oklahoma. Today, KAMO serves 17 distribution cooperatives (nine in Oklahoma and eight in Missouri). The headquarters office is located in Vinita, Oklahoma.

MEMBERSHIP

KAMO's Board of Trustees is made up of one member from each distribution electric cooperative and one member representing Associated Electric Cooperative in Springfield, Missouri. The Board, as KAMO's governing body, is responsible for the operation of the cooperative setting policy and whole rates for the members.

POWER SUPPLY

KAMO receives its electric power from Associated Electric Cooperative, Inc., Springfield, Missouri. The output from Grand River Dam Authority coal-fired Plant #2, of which KAMO owns 38% or 200 MW, is under contract to Associated.

TRANSMISSION

KAMO owns 2,082 miles of transmission line, 225 substations and serves approximately 319,000 ultimate customers. KAMO's transmission line consists of 1,812 miles of 69 KV line, 219 miles of 138 KV line, and 51 miles of 161 KV line. To maintain the system, KAMO has service offices at Cleveland, Muskogee and Vinita, Oklahoma with satellite crews at Stillwater and Collinsville, Oklahoma. In Missouri, KAMO has offices at El Dorado Springs, Neosho and Spokane.

OTHER POINTS OF INTEREST

KAMO is a non-profit generation and transmission cooperative. KAMO's 17 member distribution cooperatives are located in approximately one-fourth of Oklahoma in the northeast quadrant and approximately one-fourth of Missouri in the southwest quadrant. KAMO furnishes electric power from near Kansas City to Oklahoma City.

Kansas Electric Power Cooperative, Inc.

P.O. Box 4877
Topeka, KS 66604

Main Telephone (785) 273-7010
Main FAX (785) 271-4888
www.kepco.org

Executive Contacts

Executive Vice President & CEO	*Stephen E. Parr*
Executive Assistant	*Rita Petty*
Senior Vice President & COO	*Tom Grennan*
Vice President, Power Supply	*Les Evans*
Vice President, Administration & General Counsel	*Michael Peters*
Vice President, Finance & Controller	*Coleen M. Wells*
Vice President, Energy & Technical Services	*Robert D. Bowser*

Accounting & Finance Related Personnel

Finance	*Coleen M. Wells*
Treasury	*Coleen M. Wells*
General Accounting	*Coleen M. Wells*
Insurance - Plant	*Michael Peters*
Data Processing	*Robert D. Bowser*
Employee Benefits	*Michael Peters*
Resource Planning	*Les Evans*

Ultimate Meters Served	105,000	Taxable	No
REC Members	19	State Regulated	Yes
Other Firm Power Customers	N/A	Year Organized	1975
Power Pool	SPP	CPA - Tax	N/A
Total Plant Capacity	71 MW	CPA - Audit	BKD, LLP
# of Substations	0	**Corporate Insurance Providers**	
Miles of Transmission Line	0	Worker's Comp	Federated
Total Employees	24	Primary Liability	Federated
Union Employees	0	Commercial Umbrella	Federated
RUS Designation	KS 54	Electric Property	Federated

2006 Financial Keys

Total Assets	$206,069,092
Total Operating Revenue	$110,774,319
Net Margins	$1,046,681
Equity Ratio	9.46%
T.I.E.R.	1.12
DSC Ratio	
Cost of Debt	6.00%

MW Peak Demands

Winter	298
Summer	423

2006 MWH Sales

Member	1,790,777 @ $61.82 per MWH
Non-Mem	3,951 @ $16.22 per MWH

Kansas Electric Power Cooperative, Inc.

ORGANIZATION

Kansas Electric Power Cooperative, Inc. (KEPCo), was incorporated in 1975 as a not-for-profit generation and transmission cooperative. KEPCo is headquartered in Topeka and has a staff of 24 employees to provide power supply, engineering, marketing, economic development, legal and a host of other support services to 19 electric distribution cooperatives.

KEPCo is under the jurisdiction of the Kansas Corporation Commission (KCC) and was granted a limited certificate of convenience and authority in 1980.

KEPCo operates a comprehensive energy management/Scada system. The system is used to control and monitor KEPCo's loads, and provides each member with real-time data. The system is the largest in the state of Kansas.

MEMBERSHIP

KEPCo's 19 Member Cooperatives serve approximately 105,000 retail meters in the eastern two-thirds of rural Kansas. Collectively, they own and operate 43,000 miles of distribution lines. The KEPCo Board of Trustees consists of a representative and an alternate from each of its Member Cooperatives. The Board also elects a seven-person Executive Committee which includes the President, Vice President, Secretary, Treasurer, and three additional Executive Committee members and uses various standing committees to assist the Board.

POWER SUPPLY

KEPCo has a six percent ownership in the Wolf Creek Generating Station, a single unit nuclear power plant that has provided reliable baseload power since it began commercial operation in September, 1985. The plant furnished 33.3% in 2006 of KEPCo's energy requirements in 2006. Wolf Creek is currently evaluating a capacity uprate and a 20-year operating license extension.

In June 2002 KEPCo placed into operation 20 MW's of peaking diesel generators. The peaking capacity replaces purchases currently made from investor owned utilities.

As a consumer-owned utility, KEPCo has preference power allocations from the Southwestern Power Administration (SWPA) and Western Area Power Administration (Western). KEPCo receives a 100 MW peaking power allocation from SWPA and another 14 MW from Western which accounts for 20% of KEPCo's energy requirements. The remaining generation is obtained through wholesale purchases from five investor-owned utilities operating in Kansas and from Sunflower, another G&T operating in western Kansas.

TRANSMISSION

KEPCo does not own a transmission system. KEPCo coordinates the delivery of its wholesale power supply to 239 delivery points through existing transmission facilities. KEPCo is active in the Southwest Power Pool and the Transmission Dependent Utilities group on regional and national transmission issues.

M & A Electric Cooperative, Inc.

P.O. Box 670
Poplar Bluff, MO 63902

Main Telephone (573) 785-9651
Main FAX (573) 785-9653

Executive Contacts

General Manager	*John C. Farris*
Secretary	*Mona Johnson*
Manager of Finance	*Glen Hickey*

Accounting & Finance Related Personnel

Finance	*Glen Hickey*
Treasury	*Glen Hickey*
General Accounting	*Daryl Sorrell*
Property Accounting	*Tom Provance Jr.*
Tax Accounting	*Glen Hickey*
Internal Auditing	*Glen Hickey*
Insurance - Plant	*Daryl Sorrell*
Data Processing	*Daryl Sorrell*
Employee Benefits	*Glen Hickey*
Resource Planning	*Glen Hickey*

Ultimate Meters Served	83,372
REC Members	4
Other Firm Power Customers	0
Power Pool	ASSOCIATED
Total Plant Capacity	0
# of Substations	83
Miles of Transmission Line	979
Total Employees	43
Union Employees	26
RUS Designation	MO 60

Taxable	No
State Regulated	No
Year Organized	1948
CPA - Tax	Kraft, Miles & Tatum
CPA - Audit	Kraft, Miles & Tatum

Corporate Insurance Providers

Worker's Comp.	MECIP
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$85,287,830
Total Operating Revenue	$57,085,676
Net Margins	$3,182,273
Equity Ratio	54.17%
T.I.E.R.	2.73
DSC Ratio	2.26
Cost of Debt	5.51%

MW Peak Demands

Winter	371
Summer	383

2006 MWH Sales

Member	1,599,342 @ $35.69 per MWH
Non-Mem	0

M & A Electric Cooperative, Inc.

ORGANIZATION

M & A Electric Power Cooperative was formed by twenty-seven original incorporators on May 14, 1948. These incorporators represented distribution cooperatives from southeast Missouri and northeast Arkansas, thus M & A Electric Power Cooperative was chosen for the name of this new G&T Cooperative. None of the Arkansas cooperatives ever received power from M & A and some of the Missouri cooperatives did not either. Today M & A serves four distribution cooperatives in 18 counties in southeast Missouri..

MEMBERSHIP

M & A's Board of Directors is made up of two members from each distribution cooperative and two members representing Associated Electric Cooperative, Inc. (AECI) in Springfield, Missouri. All board members from distribution cooperatives are member directors and distribution cooperative managers are not allowed to serve as board members. The board is the governing body, setting rates as well as setting policy for all aspects of the operations of the cooperative.

POWER SUPPLY

M & A is an "all requirements" member/ owner of AECI, this agreement is through May 31, 2050. Associated was organized in 1961 by M & A and five other Missouri G&T's so that AECI could supply all of the generation needed for these six G&Ts.

TRANSMISSION

M & A owns and operates 758 miles of 69 KV line, 149 miles of 161 KV line and 58 miles of 345 KV line. We also operate and maintain 125 miles of 345 KV line and 46 miles of 500 KV line for AECI. We own and operate 82 substations as well as operate and maintain a 161/345/500 substation for AECI at the New Madrid Power Plant.

OTHER POINTS OF INTEREST

In 1970, M & A built 58 miles of the first REA financed 345 KV line in the United States. In 1980, M & A acted as agent to AECI, in the construction of 52 miles of the first 500 KV line built by an electric cooperative in the United States.

In 1993, M & A acted as agent for AECI in constructing an interconnecting 161 KV line with the Tennessee Valley Authority across the Mississippi River. This line has a 350 foot tower on each bank of the river and has a free span of 3,588 feet.

M & A serves in the area of both the highest point in Missouri (Taum Sauk Mountain) and the lowest point in Missouri which is in the "boot heel" near Cardwell, Missouri. M & A serves in areas that are very diverse. Some areas are nearly all red granite, while some areas near the Mississippi River contain some of the most fertile ground in all the world.

AECI reimburses M & A for all expenses relating to 161 KV, 345 KV and 500 KV facilities through the M & A/AECI Joint Facility Agreement. In this manner, all AECI member/owners share the expenses of operating the high voltage transmission system in Missouri, regardless of the location of the facility.

P.O. Box 13200
Grand Forks, ND 58208-3200

Main Telephone (701) 795-4000
Main FAX (701) 795-4215
www.minnkota.com

Executive Contacts

President & CEO	*David Loer*
Executive Secretary	*Gloria Enervold*
Vice President, Finance & Administration	*Gary Spielman*
Vice President, Transmission	*Wallace Lang*
Vice President, Generation	*Luther Kvernen*
Vice President, Planning & System Operations	*Alvin Tschepen*
Vice President, Legal & Government Affairs	*David Sogard*

Accounting & Finance Related Personnel

Finance	*Gary Spielman*
Treasury	*Gary Spielman*
General Accounting	*Craig Rustad - Accounting Manager*
Tax Accounting	*Craig Rustad*
Internal Auditing	*Craig Rustad*
Insurance Plant	*Doug Gregoire - Human Resource Manager*
Data Processing	*Landis Hjelle - Information Systems Manager*
Employee Benefits	*Doug Gregoire*
Resource Planning	*Alvin Tschepen*

Ultimate Meters Served	112,498
REC Members	11
Other Firm Power Customers	0
Power Pool	MAPP
Total Plant Capacity	550 MW
# of Substations	220
Miles of Transmission Line	2,942
Total Employees	338
Union Employees	185
RUS Designation	ND 20

Taxable	No
State Regulated	No
Year Organized	1940
CPA - Tax	Brady Martz & Assoc.
CPA - Audit	Brady Martz & Assoc.
Corporate Insurance Providers	
Worker's Comp.	ND State & Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	FM Global

2006 Financial Keys

Total Assets	$206,481,413
Total Operating Revenue	$155,275,887
Net Margins	$1,543,764
Equity Ratio	37.15%
T.I.E.R.	1.75
DSC Ratio	1.44
Cost of Debt	5.52%

MW Peak Demands

Winter	752
Summer	594

2006 MWH Sales

Member	3,080,882 @ $35.80 per MWH
Non-Mem	898,288@ $38.78 per MWH

GENERAL

Minnkota Power Cooperative, Inc. is a generation and transmission cooperative incorporated on May 24, 1940, under the laws of the State of Minnesota with headquarters in Grand Forks, North Dakota. It operates on a non-profit basis and is engaged in the business of providing wholesale electric service to its 11 retail distribution cooperative members. The members purchase power and energy from Minnkota pursuant to long-term all-requirements wholesale power contracts. The members are local, consumer-owned cooperative associations providing retail electric service. In general, the membership of each member consists of residential, commercial and industrial consumers within a contiguous geographic area. The member service areas, aggregating approximately 35,000 square miles, are located in the northwestern portion of Minnesota and the eastern third of ND and contain an aggregate population of approximately 300,000 people. The primary function of distribution cooperatives, such as Minnkota's members, is to supply the aggregate requirements of their retail customers through bulk purchases of power and energy and to maintain a distribution system to deliver power and energy in satisfaction of such requirements.

MANAGEMENT & ADMINISTRATION

Minnkota also serves as the operating agent for Square Butte Electric Cooperative and the Northern Municipal Power Agency. NMPA serves 12 municipals located in northwestern Minnesota and northeastern North Dakota. Minnkota is governed by a 11 member Board of Directors consisting of one Director from each of the 11 members. Directors are elected annually at meetings of delegates of the members. Regular meetings of the Board are held monthly. Special Committees, as deemed necessary, are established by the Board and appointed by the President. The officers are elected from the members of the Board of Directors by the other Board members. These are the Chairman, Vice Chairman and Secretary—Treasurer. The officers also constitute the executive committee, which makes recommendations to the Board. Minnkota currently employs 338 people and David W. Loer act as the President & CEO.

POWER SUPPLY & TRANSMISSION

Plants & Capacities as of 12-31-06: Young #1 (Coal): 250,000 kw, Grand Forks (Diesel): 10,282, Harwood (Diesel): 3,104, *Coyote (Coal): 128,100, Young #2 (Coal): 156,400 WAPA (Hydro): 114,306 , Infinity (Wind): 656 kw and other 55,830 kw for a total of 718,022 kw.

*A 30% share of Coyote is owned by NMPA. Minnkota purchases all capacity not required by the Agency.

MEMBER WHOLESALE POWER CONTRACTS

Minnkota has entered into a wholesale power contract with each of its 11 members, which is effective until December 31, 2040, and thereafter until terminated by six months written notice of either party. Each Wholesale Power Contract provides that Minnkota shall sell and deliver to the member and the member shall purchase and receive from Minnkota all electric power and energy that the member requires for the operation of the member's system.

LOAD MANAGEMENT

Starting in 1977, Minnkota and its members instituted a load management program designed to reduce the rate of peak load growth, to improve system load factor and to postpone the necessity of acquiring new, high-cost generating plants. The principal tool of the load management program is an incentive rate to install dual-fuel heating systems which can be centrally switched from electricity to an alternate fuel by Minnkota during periods of peak demand. Minnkota's net load is projected to be 570 MW in 2006-2007, instead of an uncontrolled peak demand of 850 MW without load control..

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Cameron, MO 64429

Main Telephone (816) 632-2121
Main FAX (816) 632-3114

Executive Contacts

General Manager	*Donald R. McQuitty*
Director of Transmission Systems	*John Stickley*
Director of Substations & Communications	*David McDowell*
Manager of Special Projects	*Gary D. Highfill*
Chief Financial Officer	*Kent Brown*
Manager of Communications & Government Relations	*Byron Ruach*

Accounting & Finance Related Personnel

Finance	*Kent Brown*
Treasury	*Kent Brown*
General Accounting	*Jennifer Hill*
Property Accounting	*Jennifer Hill*
Tax Accounting	*Jennifer Hill*
Internal Auditing	*Jennifer Hill*
Insurance Plant	*Kent Brown*
Data Processing	*Steven Moser, Information and Automation Systems Adm.*
Employee Benefits	*Kent Brown*

Ultimate Meters Served	69,138	Taxable	No
REC Members	7	State Regulated	No
Other Firm Power Customers	0	Year Organized	1949
Power Pool	N/A	CPA - Tax	KPMG, LLP
Total Plant Capacity	0 MW	CPA - Audit	KPMG, LLP
# of Substations	123	**Corporate Insurance Providers**	
Miles of Transmission Line	1,682	Worker's Comp.	MECIP
Total Employees	56	Primary Liability	Federated
Union Employees	0	Commercial Umbrella	AEGIS
RUS Designation	MO 72	Electric Property	Federated

2006 Financial Keys

Total Assets	$120,032,306
Total Operating Revenue	$59,481,148
Net Margins	$1,996,936
Equity Ratio	43.14%
T.I.E.R.	2.07
DSC Ratio	2.39
Cost of Debt	5.85

MW Peak Demands

Winter	315
Summer	367

2006 MWH Sales

Member	1,555,262 @ $37.47 per MWH
Non-Member	0

ORGANIZATION

N.W. was organized in 1949, as an electric power cooperative, and is not regulated by the Missouri Public Service Commission.

MEMBERSHIP

N.W.'s Board of Directors consists of two representatives from each of its seven Rural Electric Cooperative members. The Board sets wholesale rates and policies for the G&T.

POWER SUPPLY

Initially, N.W. built a coal-fired power plant at Missouri City for their power requirements along with purchased power from hydro dams in Arkansas and Missouri. With the formation of Associated Electric Cooperative, Inc. by the six G&T's in Missouri, the power supply needs of Missouri are being supplied through this super G&T. N.W. receives all of its requirements from AECI.

TRANSMISSION

N.W. provides service to the Northwest corner of Missouri with 1,682 miles of transmission line and 123 transmission and distribution substations. N.W. operates and maintains 102 miles of 345 kv line and one 345 kv substation owned by AECI.

OTHER POINTS OF INTEREST

N.W. will be adding transmission plant in the amount of $17.5 million for lines and substations to allow for the growth our seven distribution cooperatives are experiencing N.W. has allocated $83.2 million to its seven distribution cooperatives and, of that, has retired $31.5 million.

FINANCIAL RATINGS INFORMATION

N.W. is not individually rated by any ratings agency; however, it is included in the information presented by Associated Electric Cooperative, Inc.

P.O. Box 548
Columbus, NE 68602-0548

Main Telephone (402) 564-8142
Main FAX (402) 563-4272

Executive Contacts

General Manager	*Bruce A. Pontow*
Assistant General Manager	*Clint Johannes*
Executive Assistant	*Cara Sealock*

Ultimate Meters Served	144,652
REC Members	22
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	0
# of Substations	0
Miles of Transmission Line	0
Total Employees	4
Union Employees	0
RUS Designation	NE 104

Taxable	No
State Regulated	No
Year Organized	1956
CPA - Tax	N/A
CPA - Audit	N/A
Corporate Insurance Providers	
Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$15,676,770
Total Operating Revenue	$132,859,511
Net Margins	$70,941
Equity Ratio	5.26%
T.I.E.R.	0
DSC Ratio	
Cost of Debt	0%

MW Peak Demands

Winter	501
Summer	1,135

2006 MWH Sales

Member	3,499,705 @ $37.96 per MWH
Non-Member	N/A

ORGANIZATION

The Nebraska Electric G&T (NEG&T) was incorporated in 1956, with the current twenty-three members joining shortly after the formation. NEG&T was organized under Article 7 Chapters 70-701 through 70-738 ("Electric Cooperative Corporations") of the Nebraska State Statutes. NEG&T By-Laws were drafted to adhere to those state laws. The cooperative concept was, and still is, the principle that governs the operation of NEG&T.

HISTORICAL PERSPECTIVE

Political and operational concerns of rural distribution systems during the late 50's and early 60's were the catalyst for the formation of NEG&T, and the members' assurance of an affordable power supply for their customers was the goal. About this time, a new power supply was becoming available through the construction of dams along the Missouri River. NEG&T members saw the benefit of acquiring such power, but the only way to access it was to interconnect with the federal (WAPA) transmission grid. The end result was that NEG&T went to the Rural Electrification Administration (REA) and acquired the necessary funds to construct the first 230 kv line in Nebraska from Ft. Randall, South Dakota, to Columbus, Nebraska. As additional federal power became available, further interconnections and transmission facilities were needed. Again, NEG&T acquired REA funds to provide for the construction of 115 kv lines from Mission, South Dakota, to Valentine, Nebraska, Ainsworth, Nebraska, to Thedford, Nebraska, and Hinton, Iowa, to Twin Church, Nebraska. At present, NEG&T owns 36 miles of 230 kv line, 108.9 miles of 115 kv line, along with the associated substation facilities needed to interconnect with WAPA's transmission system.

POWER SUPPLY

To allow for the construction of those facilities, and to address the need for a more reliable power supply, the rurals' power supply contracts were assigned to NEG&T in 1966, with a consolidation of those contracts into one power supply contract between the Nebraska Public Power District (NPPD) and NEG&T in 1972. To convey the benefits to the rurals, power supply contracts were executed with each of NEG&T's members in 1966. Over the years, both the NPPD/NEG&T and NEG&T/Member contracts were revised and extended such that both now have terms ending in 2021.

The actions of those foresighted rural directors and managers provided for the original interconnections that have allowed Nebraska to receive an enviable supply of cost-efficient hydro power consisting of 144 megawatts of year-round firm power, 50 megawatts of summer seasonal firm power, 325 megawatts of summer seasonal peaking capacity, and 95 megawatts winter seasonal peaking capacity. In addition, there is another 50 megawatts of summer seasonal firm power and 50 megawatts summer peaking capacity provided to Nebraska from WAPA. This is designated "Irrigation Pumping Power" and has direct value to the rurals. This 100 megawatts is made available to the rurals through the previously stated contractual arrangements between NPPD, NEG&T, and its members.

HISTORICAL AND CURRENT ACTIVITIES

In 2006, NEG&T sold 3,499,705 MWH to their members with a summer peak demand of 1,135 MW. Average wholesale power purchased costs for NEG&T members was 37.96 mills in 2006.

P.O. Box 1169
Laurens, SC 29360

Main Telephone (864) 682-3159
Main FAX (864) 682-3162

Executive Contacts

President & CEO	*Charles L. Compton*
Chief Financial Officer	*Janet Davis*
Vice President, Transmission Operations	*John Boyt*

Accounting & Finance Related Personnel

Finance	*Janet Davis*
Treasury	*Janet Davis - Chief Financial Officer*
General Accounting	*Janet Davis*
Property Accounting	*Patti Hazel - Accountant*
Tax Accounting	*Janet Davis*
Internal Auditing	*N/A*
Insurance Plant	*Patti Hazel*
Data Processing	*Jay Cash*
Employee Benefits	*Maria Kennedy*
Resource Planning	*Janet Davis*

Ultimate Meters Served	N/A
REC Members	5
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	N/A
# of Substations	78
Miles of Transmission Line	126
Total Employees	39
Union Employees	0
RUS Designation	Sc 52

Taxable	No
State Regulated	No
Year Organized	1997
CPA - Tax	PricewaterhouseCoopers LLP
CPA - Audit	PricewaterhouseCoopers LLP

Corporate Insurance Providers

Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$86,351,651
Total Operating Revenue	$14,978,815
Net Margins	$234,277
Equity Ratio	14.31%
T.I.E.R.	1.05
DSC Ratio	
Cost of Debt	5.4751%

MW Peak Demands

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	N/A
Non-Mem	N/A

ORGANIZATION

New Horizon Electric Cooperative, Inc. was formed in December 1997 to provide transmission and other services to its members. Effective January 1, 1998, certain employees of Saluda River were transferred to New Horizon. Also, effective January 1, 1998, the transmission assets of Saluda River were sold to New Horizon for the net book value of those assets. Effective January 1, 2004, all remaining employees of Saluda River were transferred to New Horizon

MEMBERSHIP

New Horizon's Board of Trustees consists of one representative from each of its five Rural Electric Cooperative (REC) members. This Board sets policy and rates for its five REC members which serve upstate South Carolina.

P.O. Box 27306
Raleigh, NC 27611

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Main FAX (919) 954-7135
www.ncemcs.com

Executive Contacts

Executive Vice President & CEO	*Richard K. Thomas*
Administrator, Executive Services	*Carol G. Bumpass*
Senior Vice President & COO, NCEMC	*Joseph P. Brannan*
Senior Vice President & COO, NCAEC	*Robert B. Schwentker*
Senior Vice President & COO, TEMA	*A. Lewis Hobson*
Senior Vice President & COO, TSE Services, Inc. & EMC Technologies	*Robert H. Goodson*
Senior Vice President of Finance & CFO	*Lark S. James*
Senior Vice President, Competitive Strategies	*Carolyn H. Watts*
Senior Vice President, Corporate Relations	*Nelle P. Hotchkiss*
Senior Vice President, Corporate Strategy	*David L. Beam*
Senior Vice President, Operations & Engineering	*Barbara V. Ziberna*
Vice President, Resource Planning	*Diane C. Huis*
Vice President, Wholesale Rates	*Michael W. Burnette*
Vice President, Asset Management	*Terrence W. Ryan*

Accounting & Finance Related Personnel

Tax Accounting	*Steve Burroughs - Controller*
General & Property Accounting	*Douglas Browne, Mgr. of Financial Reporting & Compliance*
Insurance - Plant	*Robert Schwentker, Senior Vice President*
Employee Benefits	*Odessa Warren - Employee Relations Specialist*

Ultimate Meters Served	880,000	Taxable	No
REC Members	26	State Regulated	No
Other Firm Power Customers	0	Year Organized	1949
Power Pool	N/A	CPA - Tax	Deloitte & Touche, LLP
Total Plant Capacity	662 MW	CPA - Audit	Grant Thornton, LLP
# of Mobile Substations	8	**Corporate Insurance Providers**	
Miles of Transmission Line	0	Workers' Comp	CECSIF, Inc.
Total Employees	149	Primary Liability	Federated
Union Employees	0	Commercial Umbrella	Federated
RUS Designation	NC 67	Electric Property	Hartford Steam Boiler & Lloyd's of London

2006 Financial Keys

Total Assets	$1,307,077,135
Total Operating Revenue	$911,164,597
Net Margins	$6,365,873
Equity Ratio	2.18%
T.I.E.R.	1.11
DSC Ratio	1.00
Cost of Debt	5.55%

MW Peak Demands

Winter	3,195
Summer	3,353

2006 MWH Sales

Member... 15,125,412 @ $56.12 per MWH
Non-Mem.. 1,351,135 @ $45.77 per MWH

ORGANIZATION

North Carolina Electric Membership Corporation (NCEMC), originally formed in 1949, is a non-profit electric Generation and Transmission Cooperative which provides wholesale electric service and transmission to 26 electric Distribution Cooperatives (the "Members") in North Carolina.

MANAGEMENT

NCEMC's Board of Directors is composed of a Director and Manager from each of the 26 Distribution Cooperatives. The Executive Vice President and Chief Executive Officer, who reports to the Board of Directors, directs five Senior Vice Presidents, including the chief operating officers for NCEMC, NCAEC, TEMA, TSE Services Inc. and EMC Technologies, and the chief financial officer.

POWER SUPPLY

NCEMC supplies the majority of its full requirements power to its members through resales from investor-owned (IOUs) utilities. These IOUs are Carolina Power and Light, Dominion, Duke Power Company , American Electric Power, South Carolina Electric & Gas, and Southern Company.

In 1981, NCEMC acquired 644 MW of capacity in the Catawba Nuclear Station to supply a portion of its members' power requirements. NCEMC owns and operates 18 MW of diesel generators on the Outer Banks of North Carolina and is constructing 620 MW of peaking capacity to be operational in 2007.

OTHER POINTS OF INTEREST

North Carolina Association of Electric Cooperatives, Inc. (NCAEC) provides trade association services, including staff training, government relations, marketing and communications. The Tarheel Electric Membership Association, Inc. (TEMA) provides central purchasing and material supply to its members. TEMA Services Inc. provides material supply to nonmembers. TSE Services Inc. provides energy-related and marketing services to its member electric cooperatives and certain non members to meet the needs of their customers. The CEC Self Insurance Fund, Inc. (CECSIF) was incorporated in 1993 and provides statutory workers' compensation coverage to member cooperatives. EMC Technologies was formed in 2001 to provide computer and telecommunications support and services to NCEMC, members and other customers. All six companies - NCAEC, TEMA, TEMA Services, Inc., TSE, CECSIF and EMC Technologies - are affiliates of NCEMC.

In February 1998 NCEMC adopted a policy allowing members to independently procure their future wholesale power supply if they so desired. In June 2003 four members elected to exercise their rights to independently arrange for future purchase of capacity and energy effective January 1, 2004. These four members continue to be responsible for their share of energy and capacity commitments made by NCEMC prior to January 1, 2004.

NCEMC is committed in its efforts to bring the most reliable, safe and economical sources of energy to its customer-owners. NCEMC is positioned to continually improve services to meet the needs of its customers and enhance their quality of life

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Main FAX (573) 769-4358
www.northeast-power.coop

Executive Contacts

General Manager	*Douglas H. Aeilts PE*
Administrative Assistant	*Kay Simpson*
Manager of Administration & Finance	*Jackie Serbin*
Manager of Engineering & Operations	*Kevin White*
Manager of Economic Development	*Gordon Ipson*

Accounting & Finance Related Personnel

Finance	*Jackie Serbin*
Treasury	*Jackie Serbin*
General Accounting	*Missy Kizer - Controller*
Property Accounting	*Alan Embree - Accountant*
Tax Accounting	*N/A*
Resource Planning	*Kevin White*
Insurance - Plant	*Missy Kizer*
Data Processing	*Pamela Whiston - Data Processing Manager*
Employee Benefits	*Kay Simpson*

Ultimate Meters Served	55,584
REC Members	8
Other Firm Power Customers	0
Power Pool	AECI
Total Plant Capacity	0
# of Substations	90
Miles of Transmission Line	931
Total Employees	57
Union Employees	0
RUS Designation	MO 70

Taxable	No
State Regulated	No
Year Organized	1948
CPA - Tax	N/A
CPA - Audit	Wade Stables P.C.

Corporate Insurance Providers

Worker's Comp.	MECIP
Primary Liability	Federated
Commercial Umbrella	AEGIS & EIM
Electric Property	Federated

2006 Financial Keys

Total Assets	$60,863,369
Total Operating Revenue	$44,039,475
Net Margins	$2,404,266
Equity Ratio	60.57%
T.I.E.R.	3.13
DSC Ratio	2.73
Cost of Debt	5.54%

MW Peak Demands

Winter	222
Summer	236

2006 MWH Sales

Member	1,174,604 @ $35.53 per MWH
Non-Member	0

ORGANIZATION

On February 2, 1948, Northeast Power was founded by 3 rural electric cooperatives in northeast Missouri. This entity originally relied on purchased power from the US Bureau of Mines Plant at Louisiana, Missouri. In 1949, construction began on the South River diesel 7 MW generation plant located on the bank of the Mississippi River. A coal fired steam generation facility of 15 MW capacity was completed in 1952. The diesel plant combined with the steam plant provided Northeast Power with its system's power until the late 1960's. Currently Northeast Power's system is comprised of 8 distribution cooperatives with 5 located in northeast Missouri and 3 in southeast Iowa. There have been 4 managers in the history of Northeast Power. Mr. Douglas H. Aeilts, PE has been General Manager since May 2004.

MEMBERSHIP

Northeast Power's Board of Directors consists of 2 directors from each of its 8 Rural Electric Cooperative (REC) members and 2 directors from Associated Electric Cooperative, Inc. (AECI). This Board sets policy and wholesale electric rates. Northeast Power is not regulated by the Missouri Public Service Commission.

POWER SUPPLY

Northeast Power has an all - power requirements contract with AECI. Northeast Power joined with the other 5 G&T cooperatives operating in Missouri to form AECI in 1961. The goal was to establish a "Super G&T" which placed existing and future generation along with primary transmission facilities under one operating unit.

TRANSMISSION

Northeast Power has 857 miles of 69 kv transmission line and 74 miles of 161 kv line. Its service area includes 15 counties in Missouri and 10 counties in Iowa covering approximately 10,000 square miles.

OTHER POINTS OF INTEREST

Throughout the years, Northeast Power has assigned $54.3 million in patronage capital and has retired $23.4 million of this allocation. The current net patronage capital is $28.6 million.

Missouri is a three tier state with AECI as the power supplier tier. Northeast Power, along with 5 other G&T cooperatives, represents the transmission tier, serving the distribution tier which is composed of the member cooperatives.

Northeast Power is not individually rated by any ratings agency; however, it is included in the information presented by AECI.

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Main Telephone (903) 757-3282
Main FAX (903) 757-3297

Executive Contacts

General Manager .... *Richard Tyler*
Executive Secretary .... *Helen Bradshaw*

Ultimate Meters Served	133,000	Taxable	No
REC Members	6	State Regulated	No
Other Firm Power Customers	0	Year Organized	1972
Power Pool	SPP	CPA - Tax	Knuckols, Duvall, et al
Total Plant Capacity	282	CPA - Audit	Axley & Rode
# of Substations	0	**Corporate Insurance Providers**	
Miles of Transmission Line	0	Worker's Comp	
Total Employees	2	Primary Liability	
Union Employees	0	Commercial Umbrella	
RUS Designation	TX 158	Electric Property	

2006 Financial Keys

Total Assets	$229,922,952
Total Operating Revenue	$162,445,290
Net Margins	$2,640,508
Equity Ratio	31.41%
T.I.E.R.	1.33
DSC Ratio	1.18
Cost of Debt	5.40%

MW Peak Demands

Winter	721
Summer	709

2006 MWH Sales

Member	3,024,070 @ $53.71 per MWH
Non-Member	0

ORGANIZATION

Northeast Texas Electric Coop., Inc. ("NTEC") is a TX nonprofit electric generation and transmission cooperative corporation which provides wholesale electric service to its 6 member systems, all of which are distribution cooperatives (the "Distribution Cooperatives") engaged in the sale of electricity at retail to its member consumers. As of December 31, 2005, the Distribution Cooperatives served approximately 133,000 consumers in the rural areas of 18 counties of northeast Texas and two parishes in Louisiana through wholesale purchases from NTEC. Commercial operations were commenced in 1978. Although NTEC has all-requirements wholesale power supply contracts (the "Member Contracts") with all the Distribution Cooperatives, NTEC serves only that portion of each Distribution Cooperative's load which is located in the Southwestern Electric Power Company ("SWEPCO") service area. In 2006, approximately 75% of the Distribution Cooperatives' MWH sales were to residential consumers and approximately 25% of such sales were to commercial and industrial consumers. NTEC has its office in Longview, Texas and was organized in 1972. In 2005, NTEC's share of generation from the Pirkey Plant and Dolet Hills facilities, purchases from SWEPCO, and purchases from SWPA amounted to 3,114,200 MWH. Gross revenues from these sales for 2006 were $162,445,290. NTEC has acquired an 11.72% undivided interest (76.2 MW) in Henry W. Pirkey Unit #1 (the "Pirkey Plant"), a 650 MW (net) lignite-fired generating plant located near Longview in northeast Texas which began operation in January 1985, and a 5.86% undivided interest (38.1 MW) in Dolet Hills Unit #1 (the "Dolet Hills Plant"), a 650 MW (net) lignite-fired generating plant located near Mansfield, Louisiana which began commercial operation in April 1986. In June 2003, the Harrison County Power Project (HCPP) became commercially operable. HCPP is a 550 MW combined cycle plan jointly developed and constructed by NTEC and Entergy Power Ventures, LP. NTEC owns 30% of the plant, or 165MW.

FINANCING

NTEC's original investment has been financed through loans from the Federal Financing Bank guaranteed by RUS, a loan from CFC, and internally generated funds.

MEMBER COOPERATIVES

The Distribution Cooperatives are local membership cooperatives whose members are their consumers of electricity. Each Distribution Cooperative supplies the electric power requirement of its member-consumers through the purchase of power from NTEC and owns and operates its respective distribution system. Under the Member Contracts, each Distribution Cooperative has contracted with NTEC to purchase all the power required for the operation of its respective system. Each of the Member Contracts may be terminated by either party after December 31, 2027, upon not less than six months' written notice. Rates under the Member Contracts are determined by NTEC's costs and provide reasonable reserves.

REGULATIONS & TERRITORIAL PROTECTION

The wholesale rates of NTEC are not regulated by the Public Utility Commission of Texas ("PUCT"). Likewise, the Distribution Cooperatives are no longer subject to regulation by the PUCT with respect to the rates charged to their member-consumers. The Distribution Cooperatives are still regulated by the PUCT for service area certification and each Distribution Cooperative has a service area certified by the PUCT. Service area certification provides protection against duplication of service and encroachment, so long as the service provided is determined by the PUCT to be adequate or until such time as the Distribution Cooperative "opts in" to retail competition pursuant to recent legislation enacted by the 1999 Texas Legislature. NTEC is subject to a first mortgage securing loans and guarantees from RUS and CFC. Accordingly, the restrictions contained in the RUS loan and guarantee agreements provide RUS with substantial control over NTEC in such areas as accounting methods, issuance of securities, and rates and charges for the sale of electricity.

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Executive Contacts

Executive Vice President/General Manager	*Kent D. Pauling*
CFO & Vice President of Management Services	*Matthew R. Washburn*
Vice President of Engineering & Operations	*Steven J. Ver Mulm*
Vice President of Telecommunications Services	*Dennis L. Hill*
Vice President of Planning & Legislative Services	*Charles Soderberg*
Vice President of Information Services	*Larry L. Bowers*

Accounting & Finance Related Personnel

Finance	*Matthew R. Washburn*
Treasury	*Douglas A. Nemmers - Senior Accountant*
General Accounting	*Marlis M. Thieman - Accounting Services Manager*
Property Accounting	*Kathryn A. Ruden - Plant Accountant*
Tax Accounting	*N/A*
Internal Auditing	*Matthew R. Washburn*
Insurance Plant	*Rebecca J. Lauters - Manager of Human Resources & Administrative Support*
Data Processing	*Larry L. Bowers*
Employee Benefits	*Rebecca J. Lauters*
Resource Planning	*Steven J. Ver Mulm*

Ultimate Meters Served	30,714
REC Members	6
Other Firm Power Customers	1
Power Pool	MAPP
Total Plant Capacity	31 MW
# of Substations	73
Miles of Transmission Line	884
Total Employees	45
Union Employees	22
RUS Designation	IA 85

Taxable	No
State Regulated	No
Year Organized	1949
CPA - Tax	Larson, Allen, et al
CPA - Audit	Larson, Allen, et al

Corporate Insurance Providers

Worker's Comp.	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$65,981,341
Total Operating Revenue	$39,732,057
Net Margins	$1,741,739
Equity Ratio	35.28%
T.I.E.R.	2.49
DSC Ratio	1.34
Cost of Debt	5.92%

MW Peak Demands

Winter	188
Summer	177

2006 MWH Sales

Member	955,835 @ $32.71 per MWH
Non-Mem	259,066 @ $23.35 per MWH

ORGANIZATION

Thirteen rural electric cooperatives in Western Iowa formed Northwest Iowa Power Cooperative (NIPCO) on January 17, 1949. Since that time there have been three consolidations which resulted in reducing the number of member cooperatives to seven. The NIPCO headquarters is located in LeMars, Iowa. NIPCO has 45 employees including outpost crews in Harlan and Onawa, Iowa. The service territory covers 6,500 square miles in western Iowa.

MEMBERSHIP

NIPCO serves six rural electric cooperatives, one full service municipal electric cooperative (six municipals), one Class B municipal transmission cooperative (thirteen municipals) and one Class B power supply cooperative.

POWER SUPPLY

Initially hydropower from the Missouri River dams supplied all energy requirements for NIPCO's members. Power supply studies in the 1960's indicated the need for an additional power source. Cooperative leaders from an eight state region in the upper midwest formed Basin Electric Power Cooperative, headquartered in Bismarck, North Dakota. NIPCO is also a partner in a jointly owned generating plant near Sioux City, Iowa. This capacity has been leased or sold and all additional power is now supplied by Basin Electric.

TRANSMISSION

NIPCO owns, operates and maintains a transmission system consisting of 884 miles of 69 kV line, two source substations, 18 switch stations and 73 distribution substations. The telecommunications system for our core business includes a myriad of electronic devices. All of these are necessary to maintain the quality of service and reliability we at NIPCO are committed to provide to our power users. These devices range from digital and analog multiplex, two-way mobile radios and repeater stations, supervisory control and data acquisition terminals, radio controlled motor operated switches, radio operated load control devices, digital and analog microwave, power metering and a 435 mile fiber optic network which transports all the necessary data into and out of our control center. The data acquisition feature allows us to initiate our demand side load management system that helps us to curtail expensive system peaking.

OTHER POINTS

NIPCO is an active partner in various statewide organizations including the Iowa Environmental Group (environmental issues) and the Iowa Area Development Group (economic development). NIPCO is also a Touchstone Energy Partner and works with other G&T's to gain maximum results in promoting brand recognition.

NIPCO has formed associations with regional telephone companies and inter-exchange carriers. Partnering with rural communities and the local REC, NIPCO assists its member cooperatives in providing wireless communications for telephone and high speed internet services. These telecommunication ventures are being done to provide NIPCO with diversified business opportunities well into the 21st century. For more information see Web page at http://www.nipco.coop.

Oglethorpe Power Corporation

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Executive Contacts

President and Chief Executive Officer	*Thomas A. Smith*
Executive Secretary	*Jean Wheeler*
Chief Operating Officer	*Michael W. Price*
Chief Financial Officer	*Elizabeth B. Higgins*
Senior Vice President, Government Relations and CAO	*W. Clayton Robbins*
Senior Vice President, Member & External Relations	*William F. Ussery*

Accounting & Finance Related Personnel

Vice President, Treasurer	*Anne Appleby*
Vice President, Controller	*Mark Chesla*
Director, Planning & Financial Anaylsis	*Jeff Pratt*

(Some of the listed functions are outsourced & acquired thru Georgia System Operations Corp.)

General Accounting	*Ramon Calzada*
Property Accounting	*Ramon Calzada*
Tax Accounting	*Willie Collins*
Internal Auditing	*Brian Prevost*
Insurance Plant	*Tara Walker*
Data Processing	*Gary Williamson*
Employee Benefits	*Jami Reusch*

Ultimate Meters Served	1,600,000
REC Members	38
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	4,744 MW
# of Substations	N/A
Miles of Transmission Line	N/A
Total Employees	161
Union Employees	0
RUS Designation	GA 109

Taxable	Yes
State Regulated	No
Year Organized	1974
CPA - Tax	PricewaterhouseCoopers LLP
CPA - Audit	PricewaterhouseCoopers LLP
Corporate Insurance Providers	
Worker's Comp	State Fund
Primary Liability	Federated
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$4,901,745,000
Total Operating Revenue	$1,128,879,000
Net Margins	$18,201,000
Equity Ratio	12.30%
Margins for Interest	1.10
DSC Ratio	
Cost of Debt	5.46%

MW Peak Demands

Winter	6,547
Summer	8,094

2006 MWH Sales

Member	23,019,482 @ $48.98 per MWH
Non-Mem	6,228 @ $233.78 per MWH

ORGANIZATION

Oglethorpe Power Corporation is a wholesale power supplier serving 38 of Georgia's 42 Electric Membership Corporations (EMC's). These not-for-profit cooperatives provide electric retail service to more than four million Georgians. Oglethorpe Power's headquarters are in the northeastern suburbs of Atlanta. The Corporation *is the largest electric cooperative* in the United States in assets, annual revenues, kilowatt-hour sales and, through its Members, ultimate consumers served.

MEMBERSHIP

Oglethorpe Power is fully owned by its 38 Member cooperatives. These EMC's are governed by local boards, elected from within their membership. Oglethorpe Power's Board of Directors consists of 13 members. Six of these are Member-Directors elected to represent various geographical regions of the state, and one is an at-large Member-Director, five are EMC managers, one from each of the five geographical regions. The remaining two members of the Board are *outside*, independent Directors with expertise and experience from the electric utility industry and related industries.

RESTRUCTURING

In March 1997, Oglethorpe Power and its Members completed a restructuring in which the Corporation disaggregated its functions into three *distinct* operating companies. The operating companies include Oglethorpe Power Corporation, power supply and asset management; Georgia Transmission Corporation, transmission services; and Georgia System Operations Corporation, system operations. Each of the three companies functions with its own Board of Directors and President and CEO.

POWER SUPPLY

Oglethorpe Power owns undivided interest in 24 generating units representing 4,744 megawatts (MW) of nameplate generating capacity. This total includes 1,501 MW of coal-fired capacity, 1,185 MW of nuclear-fueled capacity, 632 MW of pumped-storage hydroelectric capacity, 1,411 MW of gas-fired combustion turbine capacity and 15 MW of oil-fired combustion turbine.

OTHER POINTS OF INTEREST

In the second quarter of 2003, Oglethorpe Power acquired two generation facilities previously owned by groups of its Member Systems *who are participating in these projects*. The two facilities include a six-unit, 618-MW, gas-fired combustion turbine facility, and a 468-MW, gas-fired combined cycle facility.

FINANCIAL RATINGS INFORMATION

Standard & Poor's . . . A/A-1
Moody's . . . A3/P-2
Fitch . . . A/F-1

Old Dominion Electric Cooperative

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Glen Allen, VA 23058-2310

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Executive Contacts

President and CEO	*Jackson E. Reasor*
Secretary to President	*Marian Williams*
Senior Vice President, Chief Financial Officer	*Robert L. Kees*
Senior Vice President, Power Supply	*Lisa M. Johnson*

Accounting & Finance Related Personnel

Finance	*Lynn A. W. Maloney - Vice President, Finance*
Treasury	*Karen Huddle - Manager, Treasury Services*
Accounting	*Bryan S. Rogers - Vice President, Controller*
Risk Management	*Todd T. Brickhouse - Vice President, Risk Management*
Insurance	*Thomas E. Chamberlin - Manager, Insurance and Member Financial Services*
Information Services	*Lee McDaniel - Director, MIS*
Employee Benefits	*Elissa Ecker - Vice President, Human Resources*
Resource Planning	*Rick Beam - Vice President, Power Supply Planning*

Ultimate Meters Served	535,000
REC Members	12
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	2019 MW
# of Substations	2
Miles of Transmission Line	0
Total Employees	103
Union Employees	0
RUS Designation	N/A

Taxable	No
State Regulated	No
Year Organized	1948
CPA - Tax	Ernst & Young
CPA - Audit	Ernst & Young
Corporate Insurance Providers	
Worker's Comp	Chubb
Primary Liability	Chubb
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$1,627,409,000
Total Operating Revenue	$817,515,000
Net Margins	$21,244,000
Equity Ratio	18.01%
Margins for Interest	1.39
DSC Ratio	0.89
Cost of Debt	6.49%

MW Peak Demands

Winter	2,045
Summer	2,512

2006 MWH Sales

Member	11,026,284 @ $67.70 per MWH
Non-Mem	1,349,473 @ $52.62 per MWH

ORGANIZATION

Old Dominion, incorporated under the laws of the Commonwealth of Virginia in 1948, was not staffed until 1976, when one person was hired on a permanent basis to negotiate wholesale power supply arrangements for its members. Since acquiring an interest in the North Anna Nuclear Station in 1983, Old Dominion has been an active not-for-profit power supply cooperative, providing wholesale electric service from a variety of sources to 12 Class A member distribution cooperatives that are engaged in the retail sale of electricity to approximately 535,000 member consumers (meters) located in parts of Virginia, Maryland, Delaware, and West Virginia. Old Dominion also has one Class B member.

GENERATION

Old Dominion owns an 11.6% undivided ownership interest in the North Anna Nuclear Station, a 2-unit 1,842 MW generating station located in Louisa County, Virginia, and operated by Virginia Power. In addition, Old Dominion and Virginia Power each own a 50% undivided ownership interest in the Clover Power Station, a 2-unit 882 MW coal-fired generating facility, equipped with advance pollution control, located in Halifax County near Clover, Virginia, and operated by Virginia Power. Old Dominion owns three combustion turbine projects representing 1,344 MW of capacity. Old Dominion also owns and operates approximately 20 MW of distributed generation.

REGULATION

Old Dominion's wholesale rates are not regulated by any state public service commission or by RUS, but are set by a comprehensive formulary rate that was accepted for filing by FERC in 1992. Prior to that time, Old Dominion's rates were regulated solely by its Board of Directors, subject to approval by RUS. Old Dominion's Class A members are rate-regulated by their respective state public service commissions at the retail level, and 11 of the 12 are subject to RUS supervision.

CONSOLIDATION

Old Dominion's financial statements reflect the consolidated accounts of Old Dominion, its subsidiaries and TEC Trading, Inc. ("TEC"). In accordance with the Financial Accounting Standards Board guidance, TEC, our sole class B member, is considered a variable interest entity for which we are the primary beneficiary and has been consolidated as of December 31, 2004. We have eliminated all intercompany balances and transactions in consolidation. As TEC is 100% owned by our twelve member cooperatives, its equity is presented as a non-controlling interest in our consolidated financial statements. Our non-controlling, 50% or less, ownership interest in other entities is recorded using the equity method of accounting.

FINANCIAL REPORTING

In addition to preparing an annual report designed for public distribution, Old Dominion prepares and files with the SEC an annual Form 10-K, quarterly Forms 10-Q, and Forms 8K as required. Old Dominion also files with FERC an annual Form 1 and quarterly Forms 3Q. Old Dominion's consolidated financial statements are audited by Ernst & Young. Old Dominion's accounting records conform to the Uniform System of Accounts as prescribed by FERC. In conformity with GAAP, the accounting policies applied by Old Dominion in the determination of its rates are also employed for financial reporting purposes.

TAX STATUS

As a not-for-profit electric cooperative, Old Dominion is exempt from Federal taxation under IRS Code Section 501(c)(12).

FINANCIAL RATINGS

Old Dominion's current ratings are A, A and A3 from S&P, Fitch and Moody's, respectively.

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Executive Contacts

President & CEO	*John P. Prescott*
Senior Vice President - Power Management	*Joseph W. Nadal, Jr.*
Vice President - Power Supply	*Tom Haymaker*
Vice President & CFO	*Jon R. Wissler*
Vice President - Marketing & Public Affairs	*(vacant)*
Vice President - Engineering	*Kevin M. Watkins*
Controller	*William A. Lehnebach*
Manager of Administration	*Teresa J. Stubblefield*

Accounting & Finance Related Personnel

Finance	*Jon R. Wissler*
Treasury	*Jon R. Wissler*
General Accounting	*William A. Lehnebach*
Property Accounting	*William A. Lehnebach*
Tax Accounting	*Jon R. Wissler*
Internal Auditing	*William A. Lehnebach*
Insurance	*Jon R. Wissler*
Information Services	*Kevin M. Watkins*
Employee Benefits	*Teresa J. Stubblefield*
Payables/Receivables	*Brandy Neff*
Resource Planning	*John P. Prescott*

Ultimate Meters Served	165,000
REC Members	15
Other Firm Power Customers	0
Power Pool	Northwest Power Pool
Total Plant Capacity	0 MW
# of Substations	0
Miles of Transmission Line	0
Total Employees	36
Union Employees	0
CFC Designation	OR 48

Taxable	Yes
State Regulated	No
Year Organized	1995
CPA - Tax	Moss Adams LLP
CPA - Audit	Moss Adams LLP

Corporate Insurance Providers

Worker's Comp.	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
DOM	AIG

2006 Financial Keys

Total Assets	$36,657,744
Total Operating Revenue	$167,056,500
Net Margins	$511,386
Equity Ratio	45.17%
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	N/A

MW Peak Demands

Winter	800
Summer	658

2006 MWH Sales

Member	3,955,380 @ $30.44 per MWH
Non-Mem	1,257,101 @ $36.63 per MWH

ORGANIZATION

As the impact of the 1992 Energy Policy Act became clearer, deregulation efforts accelerated, and the Bonneville Power Administration (BPA) became less competitive. The members of what is now Power Resources Cooperative (PRC) focused on how best to meet the future uncertainties during the summer of 1995. The following points guided the decision making process: (1) The next five years were going to be a transition period, (2) BPA was not going to be the lowest cost source of power during this period, and might never return to that role, (3) A successful wholesale power supplier would have to be responsive to markets, flexible to customer needs, and diversify its power supply, (4) Doing nothing to anticipate the changing market conditions was a greater risk than doing almost anything else.

As a result, PRC and its members decided to position themselves in such a way as to be able to react effectively to whatever climate emerged from the industry's restructuring. The overriding concept was that members wanted, deserved, and would be given choices. The resulting entity would agree to provide the following: (1) some level of its power supply from non-BPA sources, (2) relief from REA mortgage restrictions, (3) short term contracts for sales to members, (4) ability for members to purchase any amount, type, and duration of power from PNGC that the system desired, (5) a governance concept that responds to the impact of PNGC decisions on the members, and (6) services to the members that are best done on a joint basis. It was determined that these beliefs, goals, and philosophy could best be met by forming a new organization. Pacific Northwest Generating Cooperative (PNGC) was formed in October of 1995 and began operation January 1996 with 9 of the 14 members of PRC. The entire staff of PRC was hired by PNGC. Membership grew to 11 by the time PNGC began delivering 30% of their power supply requirements in August of 1996.

This role as an aggregator for a diversified portion of our member's power supply enabled PNGC to acquire market knowledge and experience while providing significant economic benefits to its members. A significant marketing and branding effort resulted in the adoption of the dba "PNGC Power". Tremendous market changes took place during this period, and with the expiration of the original five year contracts coming to an end, PNGC Power once again examined how to best meet its member's needs. BPA was in the early stages of contemplating a "slice of the system" product, whereby customers would be allocated a percentage of the output of the hydro dominated Federal Base System (FBS) in the Pacific Northwest and be charged the same percentage of the actual operating costs. This would enable systems to manage their own power supply in a manner that made the most operational and economic sense for their customers, and not be bound by the actions of BPA who served the entire region. Several months of intense negotiation followed, and in October 2002 PNGC Power began delivering Slice power to its members. Membership at this time had grown to 15.

The "Slice" product proved attractive to many Northwest public power entities, and BPA decided to limit it's offering. As a result, our members entered into combination Slice/Block contracts, with the Slice portion serving two thirds of their annual energy needs. PNGC Power was successful in passing federal legislation that created a Joint Operating Entity, or JOE, which enabled the members to assign these contracts to PNGC. This allows PNGC Power to take delivery of federal power from BPA for the purpose of meeting our member's loads. For the first time in our existence, we have responsibility for load following and shaping, and have constructed a sophisticated real-time operation to meet this need. Though sized to meet our annual load, the Slice product is a hydro generation dominated contract, which generates surplus and deficits depending on water conditions. PNGC Power enters the market to sell or purchase for the purpose of balancing loads and resources.

In addition to the traditional G & T role of power supply, PNGC Power also serves a significant role as spokesperson for our members in contractual and industry shaping forums, represents it's members in wholesale power supply matters, is actively involved in formulating national policy through NRECA and NRUCFC, and conducts lobbying efforts at the state and national level. PNGC Power serves a key role in shaping the new transmission environment under proposed RTO regulations. PNGC Power also provides members with economic analysis services such as rate design, cost of service, rate filings, conservation and energy efficiency, and marketing support.

POWER SUPPLY

Ten year Slice/Block contracts with BPA. Block is 226 aMW shaped to load, while Slice is 300 aMW under critical water conditions, and follows the generation of the FBS. Surplus or deficits are taken to the market.

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Executive Contacts

Executive Vice President & General Manager .... *John P. Prescott*

Accounting & Finance Related Personnel

Finance	*Jon Wissler*
Treasury	*Jon Wissler*
General Accounting	*William A. Lehnebach*
Property Accounting	*William A. Lehnebach*
Tax Accounting	*Jon Wissler*
Internal Auditing	*William A. Lehnebach*
Insurance - Plant	*William A. Lehnebach*
Data Processing	*Kevin M. Watkins*

Ultimate Meters Served	113,100
REC Members	14
Other Firm Power Customers	1
Power Pool	Northwest Power Pool
Total Plant Capacity	65 MW
# of Substations	1
Miles of Transmission Line	18
Total Employees	0
Union Employees	0
RUS Designation	OR 42

Taxable	Yes
State Regulated	No
Year Organized	1975
CPA - Tax	Moss Adam LLP
CPA - Audit	Moss Adam LLP

Corporate Insurance Providers

Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated, Chubb
DOM	AIG

2006 Financial Keys

Total Assets	$35,823,279
Total Operating Revenue	$18,141,206
Net Margins	$1,963,860
Equity Ratio	<25.56%>
T.I.E.R.	1.72
DSC Ratio	1.11
Cost of Debt	5.58

MW Peak Demands

Winter	65
Summer	65

2006 MWH Sales

Member	N/A
Non-Mem	262,087 @ $64.10 per MWH

ORGANIZATION

PRC, (formerly known as Pacific Northwest Generating Coop) was formed as a Generation & Transmission (G&T) cooperative in 1975 by seven Northwest distribution cooperatives as a response to BPA's 1975 Notice of Insufficiency (NOI). Membership eventually peaked at 21. Formal staffing commenced in 1979 with the hiring of then and current General Manager, David E. Piper.

PRC negotiated to purchase a 10% interest in the 530 MW Boardman Coal Plant, constructed and operated by PGE, which began commercial operation in 1980. With the passage of the Northwest Regional Power Act in late 1980, BPA rescinded its NOI. PRC had contracted to commence taking delivery of Boardman output in July, 1983. Previous generation was purchased by PGE at cost. Member contracts were rewritten at this point, and PRC went forward with 13 members under subscription agreements. PRC has since marketed the Boardman plant output under a variety of terms of conditions, and in 1994 began a 25 year 100% output sale to Turlock Irrigation District of Northern California.

In effect, PRC's role to date has largely been as an association working for beneficial resolutions to power supply issues on behalf of its members. It represented its members' interests in wholesale power supply matters before BPA, the Northwest Power Planning Council, the Public Power Council, the Pacific Northwest Utilities Conference Committee, and other regional groups. PRC is also actively involved in formulating national policies for its member cooperative through the National Rural Electric Cooperative Association and the National Rural Utilities Cooperative Finance Corporation. PRC conducts lobbying efforts on the national level and provides its members with support services such as cost of service studies. A wholly owned subsidiary, Pacific Northwest Services Cooperative, owns and maintains PRC's headquarters building and provides other services for the organization and its members.

PRC's members, in response to the new competitive energy market, formed a new cooperative effective January 1, 1996. The new cooperative has taken the Pacific NW Generating Coop name. PRC continues to operate, but its role has largely been reduced to managing the subscription contracts for Boardman and Coffin Butte. Administrative services are provided by contract from PNGC.

RESOURCES

PRC owns 10% of the 600 MW Boardman Coal Plant located in North Central Oregon, and a 50 MW capacity agreement of the Northwest/Southwest Intertie to transmit Boardman output. The 2.2 MW Coffin Butte landfill methane gas facility located in Oregon's Willamette Valley was completed in October of 1995.

MEMBERSHIP

PRC has two types of members. Contract members are tied to PRC through wholesale power supply contracts. These members are obligated to pay all of PRC's administrative and general costs, as well as the costs of any resources, such as the Boardman Coal Plant, in which they participate. These members currently number thirteen, and provide electric service to more than 500,000 consumers in Oregon, Washington, Idaho, Wyoming, Montana, California, Utah, and Nevada.

Rayburn Country Electric Cooperative, Inc.

P.O. Box 37
Rockwall, TX 75087

Main Telephone (972) 771-1336
Main FAX (972) 771-3046
www.rayburnelectric.com

Executive Contacts

President	*John W. Kirkland*
Administrative Director	*Annette Kirkland*
Accountant	*Shannon Fields*
Operations Manager	*Eddy Reece*
Resource Planning	*Annette Kirkland*
Chief Financial Officer	*Loretto Martin*

Ultimate Meters Served	181,385
REC Members	5
Other Firm Power Customers	0
Power Pool	SPP & ERCOT
Total Plant Capacity	N/A
# of Substations	13
Miles of Transmission Line	162
Total Employees	7
Union Employees	0
RUS Designation	TX 160

Taxable	No
State Regulated	No
Year Organized	1979
CPA - Tax	Knuckols, Duvall, et al.
CPA - Audit	Knuckols, Duvall, et al.

Corporate Insurance Providers

Worker's Comp	Texas Mutual
Primary Liability	AIG
Commercial Umbrella	AIG
Electric Property	St. Paul

2006 Financial Keys

Total Assets	$78,115,620
Total Operating Revenue	$222,652,052
Net Margin	$1,423,621
Equity Ratio	N/A
T.I.E.R.	2.00
DSC Ratio	2.01
Cost of Debt	N/A

MW Peak Demands

Winter	777
Summer	859

2006 MWH Sales

Member	2,929,158
Non-Mem	N/A

ORGANIZATION
Rayburn Country Electric Cooperative, Inc. (Rayburn Electric) was formed in 1979 to provide the wholesale power requirements for 5 rural electric distribution cooperatives which provide electric service in 16 counties in north central Texas.

MEMBERSHIP
The 5 distribution members coops of Rayburn Electric serve over 155,000 electric meters in a service area that stretches from the Red River at the border of Oklahoma approximately 150 miles to the pineywoods area of east Texas.

POWER SUPPLY
Rayburn Electric's power is purchased from Central & South West's Southwestern Electric Power Company (SWEPCO), American Electric Power, and Southwestern Power Administration's Denison Dam, Denison, Texas.

TRANSMISSION
Rayburn Electric owns and operates over 112 miles of 138 kv electric transmission line and related switching facilities and Rayburn leases 50 miles of transmission line from one of its member systems.

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Rushmore Electric Power Cooperative, Inc.

P.O. Box 2414
Rapid City, SD 57709-2414

Main Telephone (605) 342-4759
Main FAX (605) 348-2026
www.rushelec.com

Executive Contacts

General Manager .... *Vic Simmons*
Assistant General Manager .... *Todd Eliason*
Manager, Engineering .... *Michael Bowers*
Accounting Manager .... *Mark Miller*
Information Technology Manager .... *Bob Ermish*

Accounting & Finance Related Personnel

Finance .... *Mark Miller*
Treasury .... *N/A*
General Accounting .... *Mark Miller*
Property Accounting .... *Mark Miller*
Tax Accounting .... *Mark Miller*
Internal Auditing .... *Mark Miller*
Insurance Plant .... *Bob Ermish*
Data Processing .... *Darci Lanam*
Employee Benefits .... *Darci Lanam*
Resource Planning .... *Mark Miller*

Ultimate Meters Served	52,176
REC Members	8
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	0 MW
# of Substations	0
Miles of Transmission Line	0
Total Employees	21
Union Employees	0
RUS Designation	SD 44

Taxable	No
State Regulated	No
Year Organized	1950
CPA - Tax	Ketel, Thorstenson LLP
CPA - Audit	Ketel, Thorstenson LLP

Corporate Insurance Providers

Worker's Comp	Federated Rural Electric
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$25,020,998
Total Operating Revenue	$30,067,606
Net Margins	$1,816,515
Equity Ratio	88.75%
T.I.E.R.	N/A
DSC Ratio	
Cost of Debt	N/A

MW Peak Demands

Winter	196
Summer	203

2006 MWH Sales

Member	891,560 @ $29.05 per MWH
Non-Member	0

A COOPERATIVE FOR COOPERATIVES

The rural electrification program was launched in 1935 to help rural Americans obtain central station electric service in the only way it was economically feasible for them to do so - by pooling their resources. Farmers, ranchers and rural people from all walks of life joined together, took advantage of government loan programs and formed consumer-owned REC's Finally, after years of hearing it couldn't be done, the lights began coming on in the American countryside. Fifteen years later Rushmore Electric Power Cooperative was organized to give the rural electric cooperative consumers of western South Dakota something else they desperately needed but couldn't obtain in any other fashion - their own power generation and transmission system. This time, however, it wasn't simply a group of farmers and ranchers pooling their resources, but a group of the rural electric distribution cooperatives they owned.

THE BIRTH OF RUSHMORE

Prior to 1950, South Dakota's REC's were able to purchase all the power they needed from privately owned utilities. However, by the early 1950's it was becoming clear that the demand for power in the countryside would soon outgrow the supply. Suddenly the cooperatives had a major dilemma on their hands. Where were they going to purchase power when the private power companies were no longer able to fill their member's needs? The Federal Flood Control Act of 1944 had promised to provide REC's with a large future supply of electricity by authorizing the construction of dams along the Missouri River. Unfortunately, in 1950 an adequate supply of power from those dams was still more than a decade away. For the rural people of western South Dakota the answer would once again be self-reliance. After much debate, a group of five west river REC's (Black Hills Electric, Butte Electric, Lacreek Electric, West Central Electric and West River Electric) determined that their only viable option was to generate their own power to meet current demands, and expand their transmission system in anticipation of receiving federal hydro power. Rushmore Electric Power Cooperative was born. By pooling their resources in Rushmore, those five cooperatives began a partnership which has secured an adequate supply of reasonably priced electricity for the rural residents of western and central South Dakota for more than 50 years. What follows is a chronological history of Rushmore's success and growth: 1950 Rushmore is incorporated, 1952 Rushmore contracts with Black Hills Power and Light to build a generating unit at their Osage, WY plant, June 1952 Rushmore's 10,000 KW Osage unit comes on line, 1955 Tri-County Electric Association joins Rushmore bringing over 2,000 new consumers, 1955 Rushmore contracts with BHP&L again to build an additional 16,500 KW generating unit at their Kirk plant near Lead, South Dakota, 1954 the Hydro-electric generating plant at Ft. Randall Dam comes on line followed by Gavin's Point ('56), Oahe ('62) and Big Bend ('64). Federal hydro-power, marketed through the Western Area Power Administration, then provided 100% of Rushmore's requirements, 1961 eight Missouri Basin states join forces to form a regional G&T, Basin Electric Power Cooperative, 1965 Basin begins generating power from its first plant, Leland Olds Station, to meet the supplemental power requirements of its members. Between 1972 and 1984 three more cooperatives, Cam Wal ('72), Cherry-Todd ('80) and Moreau-Grand ('84), join Rushmore. 1988 Tri-County Electric leaves Rushmore to become a Class A member of Basin. In 1994 Rushmore sold both its Osage and Kirk generating units. In 2006, Rushmore purchased roughly 82% of its power from Basin and 18% from the Federal Hydro-Electric System.

RUSHMORE TODAY

Eight member systems; Serving over 52,000 consumers in western and central South Dakota; Annual electric sales of 930,944 MWH.

P.O. Box 929
Laurens, SC 29360

Main Telephone (864) 682-3169
Main FAX (864) 682-3157

Executive Contacts

President & CEO	*Charles L. Compton*
Chief Financial Officer	*Janet Davis*

Accounting & Finance Related Personnel

Finance	*Janet Davis*
Treasury	*Janet Davis - Chief Financial Officer*
General Accounting	*Janet Davis*
Property Accounting	*Patti Hazel - Accountant*
Tax Accounting	*Janet Davis*
Internal Auditing	*N/A*
Insurance Plant	*Patti Hazel*
Data Processing	*Jay Cash*
Employee Benefits	*N/A*

Ultimate Meters Served	170,000
REC Members	5
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	228 MW
# of Substations	0
Miles of Transmission Line	0
Total Employees	19
Union Employees	0
RUS Designation	SC 51

Taxable	Yes
State Regulated	No
Year Organized	1958
CPA - Tax	PricewaterhouseCoopers LLP
CPA - Audit	PricewaterhouseCoopers LLP
Corporate Insurance Providers	
Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Federated

2006 Financial Keys

Total Assets	$166,847,566
Total Operating Revenue	$156,670,095
Net Margins	<$19,887,426>
Equity Ratio	N/A
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	N/A

MW Peak Demands

Winter	723
Summer	797

2006 MWH Sales

Member	3,208,788 @ $46.59 per MWH
Non-Mem	796,860 @ $8.51 per MWH

ORGANIZATION

Saluda River Electric Cooperative, Inc. was formed in 1958. Saluda River existed essentially as a negotiating organization for its members until 1981 when a REA loan was approved to build the Catawba Nuclear Station. Catawba began commercial operation in 1985.

MEMBERSHIP

Saluda River's Board of Trustees consists of two representatives from each of its five Rural Electric Cooperative (REC) members. This Board sets policy and wholesale electric rates for the five REC members which serve upstate South Carolina. New Horizon, a cooperative owned by the same five distribution members that own Saluda River, was formed January 1, 1998 to provide transmission and other services to its members.

POWER SUPPLY

Saluda River owns 208 MW of capacity of the Catawba Nuclear Station, which has a total station capacity of 2,290 MW.

Saluda River receives all of its supplemental power requirements form Central Electric Power Cooperative, Inc.

Sam Rayburn G & T Electric Cooperative, Inc.

P.O. Box 631623
Nacogdoches, TX 75963

Main Telephone (936) 560-9532
Main FAX (936) 560-9215

Executive Contacts

General Manager .... *Edd Hargett*
CFO .... *Ryan Thomas*

Ultimate Meters Served	80,012
REC Members	3
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	55 MW
# of Substations	0
Miles of Transmission Line	0
Total Employees	7
Union Employees	0
RUS Designation	TX 154

Taxable	No
State Regulated	No
Year Organized	1979
CPA - Tax	Axley & Rode
CPA - Audit	Axley & Rode
Corporate Insurance Providers	
Worker's Comp.	Employers Mutual
Primary Liability	Employers Mutual
Commercial Umbrella	Employers Mutual
Electric Property	Travelers

2006 Financial Keys

Total Assets	$62,412,711
Total Operating Revenue	$94,558,537
Net Margins	$3,101,698
Equity Ratio	27.01
T.I.E.R.	1.70
DSC Ratio	1.42
Cost of Debt	6.75%

MW Peak Demands

Winter	400
Summer	363

2006 MWH Sales

Member	1,682,331 @ $56.20 per MWH
Non-Mem	0

ORGANIZATION

Sam Rayburn G&T Electric Cooperative, Inc. was incorporated in 1979 as an electric generation and transmission cooperative. Sam Rayburn provides wholesale electric service to its three rural electric cooperative members.

MEMBERSHIP

Sam Rayburn G&T's Board of Directors is composed of three directors from each of the distribution cooperatives. One of the directors from each cooperative is the Manager of the Cooperative and the other two are from the distribution cooperative's board of directors. The Board meets monthly.

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San Miguel Electric Cooperative, Inc.

P.O. Box 280
Jourdanton, TX 78026

Main Telephone (830) 784-3411
Main FAX (830) 784-3411

Executive Contacts

General Manager	*Marshall B. Darby*
Administrative Assistant	*Sharon Shearrer*
Administrative Services & Fuels Manager	*Michael Kezar*
E & I Maintenance Manger	*Steve Ralls*
Operations Manager	*Terry Garcia*
Mechanical Maintenance Manager	*Gene Grindle*
Engineering Manager	*Joe Eutizi*

Accounting & Finance Related Personnel

Finance	*Paula Harvey - Accounting Manager*
Treasury	*N/A*
General Accounting	*Paula Harvey*
Property Accounting	*N/A*
Tax Accounting	*Paula Harvey*
Internal Auditing	*N/A*
Insurance Plant	*Paula Harvey*
Data Processing	*Roberto Cruz - Data Processing Manager*
Employee Benefits	*Sherry Wilkerson - Personnel Manager*
Resource Planning	*None*

Ultimate Meters Served	0
REC Members	2
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	391 MW
# of Substations	1
Miles of Transmission Line	0
Total Employees	183
Union Employees	0
RUS Designation	TX 155

Taxable	No
State Regulated	No
Year Organized	1977
CPA - Tax	Gowland, Streely et al
CPA - Audit	Gowland Streely et al

Corporate Insurance Providers

Worker's Comp.	Texas Fund
Primary Liability	AIG
Commercial Umbrella	AIG
Electric Property	FM Global

2006 Financial Keys

Total Assets	$229,949,694
Total Operating Revenue	$104,447,074
Net Margins	$3,345,257
Equity Ratio	10.89%
T.I.E.R.	1.35
DSC Ratio	1.46
Cost of Debt	4.52%

MW Peak Demands

Winter	450
Summer	454

2006 MWH Sales

Member	2,937,194 @ $34.35 per MWH
Non-Mem	0

San Miguel Electric Cooperative, Inc.

ORGANIZATION

San Miguel Electric Cooperative, Inc. (San Miguel) is a cooperative corporation organized for the purpose of generating electric power. San Miguel was created on February 17, 1977, under the Rural Electric Cooperative Act of the State of Texas.

Construction of the plant was initiated as a joint venture by Brazos Electric Cooperative, Inc. (Brazos) and South Texas Electric Cooperative, Inc. (STEC) in 1974. San Miguel purchased the plant and related mining facilities upon receiving long-term financing in 1978. Commercial operation of the plant began on January 7, 1982. Brazos and STEC, which are generation and transmission cooperatives (G & T's), have entered into wholesale power contracts with San Miguel which cannot be terminated before the year 2020 under which they have agreed to purchase, and San Miguel has agreed to sell, the entire output of the plant.

MEMBERSHIP

San Miguel's Board of Directors consists of one representative from each of its 27 Rural Electric Cooperative members. Both Brazos and STEC are members, and each of their distribution cooperatives are members of the San Miguel Board. In addition, Medina Electric Cooperative, Inc. has a pooling agreement with STEC, and has a representative on the San Miguel Board. This Board sets policy and wholesale electric rates for the 27 members.

POWER SUPPLY

The Cooperative presently owns one generating unit which is located in Atascosa County. The plant is a 391 net MW mine-mouth, lignite-fired generating plant. It is fueled with lignite which is mined from deposits in Atascosa and McMullen Counties.

TRANSMISSION

San Miguel sells all of the output of the plant at the switchyard and owns no transmission lines. The transmission lines are owned by Brazos and STEC.

OTHER POINTS OF INTEREST

San Miguel has been determined by the Internal Revenue Service to be an exempt cooperative for purposes of federal income taxes, under Section 501(c) (12) of the Internal Revenue Code. San Miguel's rates have been, and are projected to remain competitive over the next decade.

FINANCIAL RATINGS INFORMATION

San Miguel is not rated by any ratings agency. San Miguel does have Pollution Control Bonds which were issued in 1984 by the Nueces River Industrial Development Authority. The bonds are currently guaranteed by the National Rural Utilities Cooperative Finance Corporation.

P.O. Box 272000
Tampa, Fl 33688-2000

Main Telephone (813) 963-0994
Main FAX (813) 264-7906
www.seminole-electric.com

Executive Contacts

General Manager/Executive Vice President (Effective 7/2/07)	*Timothy S. Woodbury*
Sr. Vice President and CFO	*John W. Geeraerts*
Vice President, Administration	*Al Garcia*
Vice President, Technical Services	*Michael P. Opalinski*
Vice President, Operations	*Floyd (Joe) J. Welborn*
Director of Corporate Compliance	*Thomas H. Turke*

Accounting & Finance Related Personnel

Accounting, Financial Planning	*Mike Maroney - Director of Accounting Services*
Finance, Tax, Risk Management	*Tim Rogers - Director of Treasury Services*
Information Systems	*William C. Cross - Director of Information Systems*
Internal Audit	*Tom Turke - Director of Corporate Compliance*
Supply Management	*Richard D. Rich - Director of Supply Management*
Employee Benefits	*W. Tip English - Manager of Human Resources*
Budgeting and Accounts Payable	*Jill Krukar - Manager*
Funds Management	*Leon Drew - Supervisor*
General Accounting	*Mike Maroney*
Resource Planning	*Lane Mahaffey - Director of Corporate Planning*
Rates	*Trudy Novak - Director of Planning & Bulk Power Contracts*

Ultimate Meters Served	880,000
REC Members	10
Other Firm Power Customers	0
Power Pool	None
Total Plant Capacity(Winter)	2,222 MW
# of Substations	4
Miles of Transmission Line	419
Total Employees	484
Union Employees	170
RUS Designation	FL 41

Taxable	Yes
State Regulated	No
Year Organized	1948
CPA - Tax	Pricewaterhouse Coopers LLP
CPA - Audit	Pricewaterhouse Coopers LLP

Corporate Insurance Providers

Worker's Comp	FRESIF
Primary Liability	Federated
Commercial Umbrella	AEGIS/EIM
Electric Property	FM Global

2006 Financial Keys

Total Assets	$1,410,567,844
Total Operating Revenue	$1,173,424,620
Net Margins	$14,281,618
Equity Ratio	6.96%
T.I.E.R.	1.24
DSC Ratio	1.05
Cost of Debt	5.17%

MW Peak Demands

Winter	4,098
Summer	3,518

2006 MWH Sales

Member	16,777,086 @ $68.59 per MWH
Non-Mem	229,661 @ $59.81 per MWH

Organization/Membership

Seminole was incorporated in 1948 to unify member representation in wholesale power negotiations and currently provides wholesale electric service to 10 member cooperatives. In 1975, each member entered into a 45 year wholesale power contract (WPC). Currently, nine of Seminole's 10 members, representing 79% of current load, have entered into amendments which extend their WPCs through 2045 and provide for some degree of flexibility in the future. Such amendments provide for all-requirements service through 2020, with an option, exercisable by each member, to elect to convert to a form of partial requirements service with at least three years notice, commencing no earlier than 2021. Seminole's 10th member has chosen not to extend its WPC.

Seminole's members provide retail electric service to nearly1.7 million people in 46 of Florida's 67 counties and serve primarily residential and small commercial consumers.

Power Supply/Transmission

In 1975, Seminole acquired a 15 MW share of Progress Energy Florida's Crystal River 3 nuclear plant which began commercial operation in 1977. Seminole constructed two 650 MW coal units (Seminole Generating Station - Units 1 and 2) in Putnam County, Florida, placing both units into service in 1984. The Payne Creek Generating Station, located in Hardee County, Florida is comprised of a 500 MW gas fired combined cycle facility which began commercial operations in 2002 and 310 MW of aero derivative combustion turbine peaking units which began commercial operation in December 2006. In March 2005, Seminole announced plans for a third coal unit at the Seminole Generating Station to be in service in 2012. This project will include a new 750 MW coal unit which is needed for load growth, replacement of expiring purchase power contracts, and to meet Seminole's fuel diversity objectives. Additionally, Seminole has several pollution control upgrade projects underway on the two existing coal units at the Seminole Generating Station. Approximately half of Seminole's capacity resources are provided through purchased power contracts.

Seminole serves only 10% of its member load requirements from its own transmission system. The balance is served primarily under long term network type transmission contracts with FPL and Progress Energy. Seminole owns and operates the 230 kV transmission facilities connecting its two generating stations to the grid.

Financing

To date, Seminole's principal sources of financing have been RUS-guaranteed loans from FFB, issuances of tax-exempt bonds, leasing, and most recently, privately placed debt. The use of alternative financing has resulted in more than 50% of the cost of Seminole's utility assets being financed with non-federal funding. Seminole maintains an "A-" Issuer Credit Rating from Standard and Poor's.

Generation Planning Outlook

At present, Seminole's power supply portfolio includes a substantial amount of purchased capacity. This resource mix resulted from competitive bidding for power supply in prior years. If purchased power alternatives are not competitive in the future, Seminole will be challenged to acquire necessary financing for more self-build generation projects. Seminole is involved almost annually acquiring significant blocks of capacity to meet its needs 3-7 years into the future due to expiring purchased power contracts and robust load growth. The third coal unit in 2012 will lessen Seminole's reliance on natural gas. Developing clean coal technologies such as IGCC will be of increasing interest in the future for serving base load requirements. Seminole has added a significant amount of renewable energy in recent years, even though at present there is no requirement to do so. In Florida, Seminole's regional options for competitively priced renewable type energy are confined to biomass, landfill gas, and waste-to-energy facilities.

P.O. Box D
Marshfield, MO 65706

Main Telephone (417) 468-2615
Main FAX (417) 468-2611
www.shomepower.com

Executive Contacts

General Manager	*Gary L. Fulks*
Manager, Finance and Accounting	*John Richards*
Manager, Operations and Engineering	*Kevin Hopper*
Manager, Equipment and Materials	*Mark Burchfield*
Manager, Computer Services	*Les Nunn*
Manager, Engineering Services	*Darold Phillips*
Chief Engineer of Operations	*Jeff Neas*
Chief Transmission and Construction Engineer	*Terry Arndt*
Director of Telecommunications	*Mark Keeling*
Director of Business Development	*Tim Lewis*
Director of Communications and Safety	*Jerry Hartman*
Controller	*Denise Stevens*

Accounting & Finance Related Personnel

General Ledger & Accounts Receivable	*Rebecca Gunn, Senior Accountant*
Payroll & Payables	*Connie Hubbard, Senior Accountant*
Property & Insurance	*Melody Mikkelsen, Senior Accountant*
Sho-Me Technologies Accounting	*Rhonda Whitlock, Technologies Accountant*

Ultimate Meters Served	250,000
REC Members	9
Other Firm Power Customers	18
Power Pool	Member of AECI
Total Plant Capacity	3 MW
# of Substations	157
Miles of Transmission Line	1,738
Total Employees	149
Union Employees	77
RUS Designation	MO 59

Taxable	Yes
State Regulated	No
Year Organized	1941
CPA	Whitlock, Selim & Keehn, LLP

Corporate Insurance Providers

Worker's Comp.	Self-Insured Pool
Primary Liability	Federated
Commercial Umbrella	AEGIS/EIM
Electric Property	Self Insured

2006 Financial Keys

Total Assets	$261,235,992
Total Operating Revenue	$169,119,453
Net Margins	$15,222,683
Equity Ratio	47.53%
T.I.E.R.	3.46
DSC Ratio	2.53
Cost of Debt	5.87%

MW Peak Demands

Winter	849
Summer	872

2006 MWH Sales

Member	2,744,628 @ $40.20 per MWH
Non-Mem	1,179,209 @ $38.78 per MWH

ORGANIZATION

The predecessors of Sho-Me Power Electric Cooperative (Sho-Me) were Sho-Me Power Cooperative, Inc., formed in 1941 as an agriculture cooperative, followed by Sho-Me *Power Corporation*, incorporated in 1947 as a public utility. This entity, fully regulated by the Missouri Public Service Commission (MoPSC), provided retail service to many communities until 1985, and was converted to an electric cooperative in 1992, removing itself from MoPSC rate regulation.

MEMBERSHIP

Sho-Me's Board of Directors consists of one representative from each of its nine Rural Electric Cooperative (REC) members. This Board sets policy and wholesale electric rates for the 9 REC members and 17 all requirements municipal customers as well as Sho-Me's sole remaining retail customer, Fort Leonard Wood.

POWER SUPPLY

The Little Niangua hydro project, built during the 1920s, continues to provide Sho-Me with 3 MW of "river-run" power, but today that accounts for less than 1% of its requirements. Over 99% of Sho-Me's power needs are satisfied by Associated Electric Cooperative, Inc. (AECI). AECI was created by Sho-Me and the five other G&T cooperatives operating in Missouri in 1961.

TRANSMISSION

Sho-Me operates and maintains over 2,000 miles of electrical transmission lines and over 150 substations that operate at voltages from 13 kv to 345 kv. Sho-Me's service area covers approximately 25% of the State of Missouri, yet the personnel needed to respond to service requests are located at three crew facilities, none located more than an hour from any substation.

TRENDS

2006 was a year of transition as AECI raised rates to Sho-Me for the first time in twenty years. Sho-Me's Board of Directors elected to raise rates to themselves higher than immediately needed in order to forego seeking annual increases to keep pace with AECI's projected needs. October 25th marked the end of an era as John K. Davis, Sho-Me's General Manager since 1975, passed away. Gary L. Fulks, formerly the division manager of AECI, assumed the role of General Manager on April 9, 2006.

DIVERSIFICATION

Sho-Me Engineering, LLC, continued to provide consulting engineering services to the members of Sho-Me Power, as well as a *variety of non-member clients.* Work plans, work order inspection and contract administration are the primary focus of this subsidiary.

Sho-Me Technologies, LLC provides diverse telecommunications service to a wide variety of clients. The client list continues to be *dominated by telephone* companies, schools, medical providers, banks, Internet service providers and government. Traditional voice applications are rapidly being replaced by all data networks using Voice Over Internet Protocol (VOIP). Sho-Me Technologies also provides backup hosting services for a variety of networks and is poised to provide more telecom services through its cooperatively owned strategic partners.

P.O. Box 2165
Benson, AZ 85602

Main Telephone (520) 586-5000
Main FAX (520) 586-5332
www.aztouchstoneenergy.com

Executive Contacts

Chief Executive Officer	*Donald W. Kimball*
Executive Assistant	*Valerie Nicholson*
Chief Financial Officer	*Dirk C. Minson*
Chief Operating Officer	*Robert Hewlett*

Accounting & Finance Related Personnel

Finance	*Dirk C. Minson*
Treasury	*Gary Pierson, Financial Services Mgr.*
Accounting	*Richard Franklin*
Internal Auditing	*James Felch, Internal Auditor*
Insurance	*Patrick Ledger*
Data Processing	*Lee Wilfert, CIO*
Employee Benefits	*Emery Silvester, Human Resource Mgr.*

Ultimate Meters Served	N/A
REC Members	N/A
Other Firm Power Customers	N/A
Power Pool	N/A
Total Plant Capacity	N/A
# of Substations	N/A
Miles of Transmission Line	N/A
Total Employees	242
Union Employees	111
RUS Designation	None

Taxable	Yes
State Regulated	No
Year Organized	2000
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Moss AdamsLLP
Corporate Insurance Providers	
Worker's Comp	AZ State Fund
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	N/A

2006 Financial Keys

Total Assets	$9,095,130
Total Operating Revenue	$63,292,761
Net Margins	N/A
Equity Ratio	N/A
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	None

MW Peak Demands

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	N/A
Non-Member	N/A

ORGANIZATION

Sierra Southwest Cooperative Services, Inc. (Sierra) was created in September 1997 as a part of the restructuring of Arizona Electric Power Cooperative, Inc., (AEPCO) which occurred in 2001. Sierra serves two primary roles: the first, as the shared service provider of staffing/labor and services to Arizona Electric Power Cooperative, and Southwest Transmission Cooperative, Inc. (SWTransco). Secondly, Sierra is a retail energy service provider to primarily commercial and industrial customers in Arizona, California and Nevada.

Sierra is a member-owned, non-profit Arizona cooperative corporation organized to provide personnel staffing and energy services and products to its members and other customers. Touchstone Energy Promotional Products, Inc. (TSE), its wholly owned subsidiary, was organized for purpose of retail merchandise sales.

The Cooperative is organized with three classes of members. Class A Members consist of electric utilities which are or have been beneficiaries of the Rural Electrification Act of 1936 and have, or will have, agreements to purchase power from Arizona Electric Power Cooperative, Inc. and transmission agreements with Southwest Transmission Cooperative, Inc. and receive, or will receive, services from the Cooperative pursuant to a Resource Integration Agreement. There were six Class A Members as of December 31, 2005 and 2004.

Class B Members consist of generation and transmission electric cooperatives, which have, or will have, agreements with the Cooperative whereby personnel staffing services are purchased from the Cooperative. AEPCO and SWTransco were the two Class B Members as of December 31, 2005.

Class C Members consist of entities which purchase energy products from the Cooperative or purchase, use, or receive a service, product, commodity, equipment or facility from or through the Cooperative under agreements with a term of one year or greater. There were 46 Class C Members as of December 31, 2005.

Class A, Class B, and Class C Members were collectively referred to as Members.

P.O. Box 15849
Hattiesburg, MS 39404

Main Telephone (601) 268-2083
Main FAX (601) 261-2351

Executive Contacts

General Manager .... *James Compton*
Assistant General Manager .... *Marcus Ware*
Executive Secretary .... *Yvette Evans*
Manager of Finance (Interim) .... *Jim Borsig*
Manager of Engineering .... *Terry Lee*
Manager of Transmission Construction .... *Jerry Pierce*
Manager of Human Resources and Development .... *Benny Murray*
Manager of Power Supply .... *Nathan Brown*
Manager of Production .... *Roger Smith*
Manager of Corporate Information and Planning .... *Jim Borsig*
Manager of Transmission Operations .... *Brad Wolfe*

Accounting & Finance Related Personnel

Finance .... *Jim Borsig*
Treasury .... *Camille Daglio - Director of Finance*
General Accounting .... *Bobby Vinson - Director of Accounting*
Property Accounting .... *Bobby Vinson*
Internal Auditing .... *Mike McCrary - Director of Audit*
Insurance Plant .... *Camille Daglio*
Data Processing .... *Carl Lindau - Director of Computer Information Systems*
Employee Benefits .... *Benny Murray*
Resource Planning .... *Nathan Brown*

Ultimate Meters Served	390,499
REC Members	11
Other Firm Power Customers	0
Power Pool	SPP
Total Plant Capacity	1578 MW
# of Substations	247
Miles of Transmission Line	1,641
Total Employees	282
Union Employees	0
RUS Designation	MS 53

Taxable	No
State Regulated	No
Year Organized	1941
CPA - Tax	N/A
CPA - Audit	Carr, Riggs & Ingram, LLC

Corporate Insurance Providers

Worker's Comp	Liberty Mutual
Primary Liability	Federated
Commercial Umbrella	AEGIS
Electric Property	AEGIS

2006 Financial Keys

Total Assets	$1,011,163,017
Total Operating Revenue	$636,991,811
Net Margins	$11,136,341
Equity Ratio	11.03%
T.I.E.R.	1.25
DSC Ratio	1.14
Cost of Debt	5.40%

MW Peak Demands

Winter	1,978
Summer	1,992

2006 MWH Sales

Member	9,528,089 @ $68.16 per MWH
Non-Mem	7,373 @ $73.08 per MWH

ORGANIZATION

South Mississippi Electric Power Association's sole business is to provide affordable and reliable electric energy to its Member cooperatives. South Mississippi Electric is headquartered on Highway 49 North in Hattiesburg, Mississippi. The Association employs more than 283 skilled and professional employees.

Representatives from seven electric power associations chartered South Mississippi Electric in April 1941. Construction efforts ceased due to World War II and did not resume until 1958. Although legal delays were encountered, the first generating plant was placed into service in 1970, using natural gas and fuel oil as its fuel sources.

MEMBERSHIP

South Mississippi Electric is a non-profit cooperative which generates, transmits and sells wholesale power to eleven Member distribution cooperatives. These eleven Member systems own and maintain approximately 53,500 miles of distribution line and provide service to more than 390,000 meters in 56 counties in Mississippi.

POWER SUPPLY

South Mississippi Electric's generating fleet includes a coal-fired plant near Purvis and 10 percent undivided interest in the Grand Gulf Nuclear Station in Port Gibson. Gas and/or fuel oil-fired generation equipment includes units near Moselle and eight combustion turbine units at Sylvarena, Silver Creek, Benndale, and Paulding, utilized as generating capacity to meet peak demand. The Association also has a long-term contract for rights to the output of a 280 megawatt gas-fired unit in north Mississippi.

TRANSMISSION

The modern transmission system delivers electric energy through 1,641 miles of high-voltage transmission line. This includes 987 miles of 69 kV, 226 miles of 115 kV, 345 miles of 161 kV lines, and 83 miles of 230 kV lines.

P.O. Box 119
Nursery, TX 77976

Main Telephone (361) 575-6491
Main FAX (361) 576-1433
www.stec.org

Executive Contacts

General Manager .... *Michael Packard*

Accounting & Finance Related Personnel

Finance	*Mike Coyle - Financial Analyst*
Treasury	*Frances Nitschmann*
Accounting	*Frances Nitschmann*
Property Accounting	*Frances Nitschmann*
Tax Accounting	*Frances Nitschmann*
Internal Auditing	*Frances Nitschmann*
Insurance Plant	*Kathleen Sproles*
Data Processing	*Kathleen Sproles - Accounting Systems Supervisor*
Employee Benefits	*Terry Thomas*

Ultimate Meters Served	192,845
REC Members	8
Other Firm Power Customers	0
Power Pool	ERCOT
Total Plant Capacity	233 MW
# of Substations	96
Miles of Transmission Line	1,277
Total Employees	176
Union Employees	0
RUS Designation	TX 148

Taxable	No
State Regulated	Yes
Year Organized	1944
CPA - Tax	Washington Utility Group
CPA - Audit	Bumgardner, Morrison & Co.

Corporate Insurance Providers

Worker's Comp	Texas Mutual Insurance
Primary Liab.	AIG
Commercial Umbrella	AEGIS
Electric Property	AIG/Liberty/AEGIS

2006 Financial Keys

Total Assets	$335,644,754
Total Operating Revenue	$150,150,084
Net Margins	$3,069,399
Equity Ratio	18.19%
T.I.E.R.	1.24
DSC Ratio	1.243
Cost of Debt	5.16%

MW Peak Demands

Winter	285
Summer	307

2006 MWH Sales

Member	2,188,796 @ $58.64 per MWH
Non-Mem	144,087 @ $45.45 per MWH

ORGANIZATION

STEC is an electric cooperative which purchases and generates electricity in bulk and transmits this electricity for sale at wholesale to the following retail electric distribution cooperatives:

Wharton County Electric Cooperative Inc.
Karnes Electric Cooperative, Inc.
Nueces Electric Cooperative, Inc.
San Patricio Electric Cooperative, Inc.
Victoria Electric Cooperative, Inc.
Jackson Electric Cooperative, Inc.
Medina Electric Cooperative, Inc.
Magic Valley Electric Cooperative, Inc.

STEC member cooperatives are engaged in the rendition of retail electric service, and, to this end, operate electrical distribution facilities to provide retail electric utility service to end use customers located in their respective certified retail service areas. The distribution cooperatives rely upon STEC to obtain and deliver to them their requirements for electricity. The distribution cooperatives listed above comprise the total membership and all of the wholesale customers of STEC. The operations of STEC are limited to the purchase, generation, transmission and sale at wholesale of electricity. STEC does not provide retail electric utility service.

The Board of Directors of South Texas Electric Cooperative, Inc. consists of one representative and one alternate from each of its eight member distribution cooperatives. Currently, STEC serves approximately 146,000 homes and businesses through its eight member distribution cooperative in a 42-county area stretching 240 miles along the Texas Gulf Coast.

STEC owns and operates transmission and generation facilities and contracts for additional generation capacity to provide for the bulk power needs of STEC member cooperatives. In fulfillment of this obligation STEC has contracted with San Miguel Electric Cooperative, Inc. (San Miguel) to purchase a portion of the output of its generation station. STEC is contractually responsible for and entitled to take 50% of the capacity of San Miguel. Brazos Electric Power Cooperative, Inc., (Brazos) purchases the balance of such capacity. STEC and Brazos are obligated to buy power from the plant and to pay all construction and operating costs of the 391 megawatt lignite-fired San Miguel generating station plant, which began commercial operation January 6, 1982.

STEC directly owns and operates two gas turbines of 11 megawatts each, one 22 megawatt steam generator and a 185 MW combined cycle plant. STEC also owns and operates approximately 1,277 miles of transmission line. STEC also owns the 75 megawatt Pearsall generation station. STEC receives 100% of the output of the hydroelectric generation from the dams at Falcon and Amistad lakes on the Rio Grande River. This generation is run of the river generation; that is, the generation has lowest priority use of water, with the result that generation is available when water is discharged for some other use.

11543 Lake of Egypt Road
Marion, IL 62959

Main Telephone (618) 964-1448
Main FAX (618) 964-1867

Executive Contacts

President................ *Timothy W. Reeves*
Accounting & Finance Department Manager................ *Stephanie L. Oxford*
Production Department Manager................ *Todd Gallenbach*
Systems & Power Marketing Department Manager................ *Bill Hutchison*

Accounting & Finance Related Personnel

Finance................ *Stephanie L. Oxford*
Treasury................ *Stephanie L. Oxford*
General Accounting................ *Stephanie L. Oxford*
Property Accounting................ *Paul Furtak - Supervisor of Accounting*
Tax Accounting................ *Stephanie L. Oxford*
Insurance - Plant................ *Stephanie L. Oxford*
Data Processing................ *Greg Newberry - Network Administrator*
Employee Benefits................ *Diane Karnes - Human Resources Coordinator*
Resource Planning................ *Bill Hutchinson*

Ultimate Meters Served	76,817	Taxable	No
REC Members	6	State Regulated	No
Other Firm Power Customers	2	Year Organized	1948
Power Pool	SERC	CPA - Tax	Kerber, Eck & Braeckel LLP
Total Plant Capacity	433 MW	CPA - Audit	Kerber, Eck & Braeckel LLP
# of Substations	145	**Corporate Insurance Providers**	
Miles of Transmission Line	862	Worker's Comp	ICWCG
Total Employees	118	Primary Liability	Federated
Union Employees	89	Commercial Umbrella	Federated
RUS Designation	IL 50	Electric Property	ACE

2006 Financial Keys

Total Assets	$341,795,877
Total Operating Revenue	$123,818,641
Net Margins	$10,104,457
Equity Ratio	13.14%
T.I.E.R.	1.68
DSC Ratio	2.19
Cost of Debt	5.15%

MW Peak Demands

Winter	402
Summer	408

2006 MWH Sales

Member ......1,883,652 @ $56.54 per MWH
Non-Mem ......330,513 @ $46.15 per MWH

ORGANIZATION

Southern Illinois Power Cooperative (SIPC) is a generation and transmission cooperative serving six distribution cooperatives. SIPC was originally organized in 1948 by Egyptian Electric Cooperative Assn., South Eastern Illinois Electric Co-op and Southern Illinois Electric Co-op and the city of Cairo, Illinois. The purpose of the group was to obtain bulk power from the Tennessee Valley Authority through a Kentucky linkage. That attempt failed, but the new organization was able to obtain a notable reduction in electric rates when it signed a ten year bulk power contract for its member systems in 1950. A major goal accomplished, the organization then became dormant until 1957, when it was revived by the three member cooperatives. In 1959, the three electric cooperatives decided to apply to the REA for a $25 million loan with which to construct their own power supply facilities. The loan request made history when on February 23, 1960, REA announced approval of the loan, the first REA loan for a *generation facility.*

In 2000, SIPC admitted two additional members – Clinton County Electric Coop and Tri-County Electric Coop.

On January 1, 1999, Monroe County Electric Cooperative began purchasing 100% of their energy from SIPC. They joined SIPC as the sixth member in 2002.

MEMBERSHIP

SIPC's Board of Directors is composed of three representatives and the manager from each of the member systems.

POWER SUPPLY

SIPC owns and operates its own power supply. In 2003, SIPC completed a significant plant upgrade by replacing three aging small boilers with one 120 MW circulating fluidized bed boiler. The new boiler *greatly enhances reliability and* increased capacity slightly. The new boiler, which operates at a lower temperature than the cyclone boilers it replaced, is capable of burning a variety of fuels. SIPC currently fuels the boiler with locally available mine waste.

In 2003, SIPC also installed two 70 MW simple cycle combustion turbines to provide peaking power. In addition to the recently installed generation assets, SIPC operates a 173 coal-fired unit, which came online in 1978. This unit is equipped with a wet scrubber and selective catalytic reduction technology. The scrubber was part of the original 1978 construction, while the SCR was added in 2003

TRANSMISSION

SIPC's 862 miles of transmission lines and 86 substations provide electricity to over 75,000 end customers. SIPC constructs, owns and operates all transmission lines of 69 kv and above to service the distribution cooperatives. SIPC is a member of the Midwest ISO.

OTHER POINTS OF INTEREST

SIPC has made a major contribution to the economic well being of the 19 county region in southern Illinois known as "Little Egypt." SIPC *is located on the shores of Lake Egypt*, a 2,300 acre lake with 93 miles of shoreline developed by SIPC for cooling water.

SIPC utilizes locally available coal and carbon which enables SIPC to meet its responsibilities to the diversified economy of agriculture, mining, manufacturing and recreation in southern Illinois.

SIPC is a member of ACES Power Marketing, Midwest ISO, and Southeast Reliability Council (SERC).

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Benson, AZ 85602

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www.southwesttransmission.org

Executive Contacts

Chief Executive Officer	*Donald W. Kimball**
Executive Assistant	*Valerie Nicholson**
Chief Financial Officer	*Dirk C. Minson**
Chief Loan Officer	*Gary Pierson**
Sr. Vice President & Chief Operating Officer	*Larry Huff*

*Employed by Sierra Southwest

Accounting & Finance Related Personnel

Finance	*Dirk C. Minson **
Treasury	*Gary Pierson, Financial Services Mgr.**
Property Accounting	*Nadine Azzopardi**
Tax Accounting	*Richard Franklin**
Internal Auditing	*James Felch, Internal Auditor**
Insurance	*Patrick Ledger**
Data Processing	*Lee Wilfert, CIO**
Employee Benefits	*Emery Silvester, Human Resource Mgr.**
Resource Planning	*Cliff Cathers**
Manager of Accounting	*Valerie Hoyt**

Ultimate Meters Served	N/A
REC Members	7
Other Firm Power Customers	6
Power Pool	N/A
Total Plant Capacity	N/A
# of Substations	21
Miles of Transmission Line	608
Total Employees	42
Union Employees	0
RUS Designation	AZ 31

Taxable	No
State Regulated	Yes
Year Organized	2000
CPA - Tax	Deloitte & Touche LLP
CPA - Audit	Moss Adams LLP

Corporate Insurance Providers

Worker's Comp.	AZ State Fund
Primary Liability	Federated
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$106,503,137
Total Operating Revenue	$36,282,325
Net Margins	N/A
Equity Ratio	N/A
T.I.E.R.	N/A
DSC Ratio	N/A
Cost of Debt	5.61%

MW Peak Demands

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	N/A
Non-Member	N/A

ORGANIZATION

Southwest Transmission Cooperative, Inc. (SWTransco) was created in September 1997 as a part of the restructuring of Arizona Electric Power Cooperative, Inc. (AEPCO) which occurred in 2001. SWTransco took over ownership, operation, and future construction of the transmission system formerly owned by AEPCO.

The Cooperative is organized under Arizona law as a non-profit Arizona rural electric transmission cooperative, which provides electric transmission and ancillary services to its customers. The Cooperative was organized with two classes of Members. Class A Members consist of non-profit electric cooperative or non-profit membership corporations which are electric utilities that are or have been beneficiaries of the Rural Electrification Act of 1936 and have or will have agreements wherein their power and associated energy are delivered using transmission and related facilities owned by the Cooperative and/or transmission rights in third party systems controlled by the Cooperative; and that have each joined with the other Class A Members in the Cooperative's operations in order to share the benefits and costs of ownership of an entity engaged in providing transmission services for the benefit of its members. There are currently six Class A Members. Class B Members consist of generation and transmission electric cooperative organized under Arizona law and other electric utilities which currently have, or will have agreements with the Cooperative whereby transmission services are purchased from the Cooperative. There are currently three Class B Members.

Soyland Power Cooperative, Inc.

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Jacksonville, IL 62640

Main Telephone (217) 245-6161
Main FAX (217) 245-1705
Accounting Telephone (217) 243-1615
Accounting FAX (217) 243-4286

Executive Contacts

President & CEO	Robert K. Harbour
Vice President Power Delivery	Daniel Breden
Vice President Finance & Accounting	Lyndon Gabbert
Vice President Engineering/Operations/Planning	John Dalton
Director Administrative Services	Greg Nieman

Accounting & Finance Related Personnel

Finance and Treasury	Lyndon Gabbert
General Accounting	Kirsten Pratt
Property Accounting	Kirsten Pratt
Tax Accounting	Lyndon Gabbert
Resource Planning	John Dalton
Information Technology	Sheila Kunkle

Ultimate Meters Served	79,000
REC Members	11
Other Firm Power Customers	0
Power Pool	MISO/ MAIN
Total Plant Capacity	176 MW
# of Substations	86
Miles of Transmission Line	584
Total Employees	58
Union Employees	0
RUS Designation	N/A

Taxable	No
State Regulated	No
Year Organized	1963
CPA - Tax	BKD, LLP
CPA - Audit	BKD, LLP

Corporate Insurance Providers

Worker's Comp	Federated
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	Chubb

2006 Financial Keys

Total Assets	$84,224,676
Total Operating Revenue	$84,950,951
Net Margins	$640,607
Equity Ratio	18.50%
T.I.E.R.	1.19
DSC Ratio	1.36
Cost of Debt	5.93%

MW Peak Demands

Winter	274
Summer	337

2006 MWH Sales

Member	1,492,128 @ $56.04 per MWH
Non-Member	0

ORGANIZATION

Soyland Power Cooperative is a member-owned, not-for-profit electric generation and transmission cooperative supplying wholesale electricity to 11 member distribution cooperatives. These distribution cooperatives provide retail electric service to over 79,000 ultimate consumers in central Illinois.

Soyland was organized by six distribution cooperatives in September, 1963, under the General Not-For-Profit Corporation Act of the State of Illinois. Leaders of those cooperatives saw Soyland as a way to gain energy independence and control over electric power costs. In 1975, nine additional cooperatives joined the original six (two have since merged), and plans were launched to develop a reliable power supply system. Western Illinois Power Cooperative, with seven member distribution cooperatives systems merged into Soyland in March of 1989.

The Soyland board of directors adopted a policy in 1996 that allows a member distribution cooperative the opportunity to buy out of its wholesale power contract and membership if it so chooses. The intent of the policy was to provide members with choices without penalizing the remaining members. Ten members have elected to buy out of Soyland since the inception of this policy.

Soyland entered into a business alliance with Allegheny Electric Cooperative, a Pennsylvania based generation and transmission cooperative located in Harrisburg, Pennsylvania in the fall of 2000. The alliance, known as Continental Cooperative Services (CCS) was created to capitalize on the benefits of sharing resources and rapidly changing industry knowledge and experience, while creating greater leverage in negotiating larger energy purchases.

In August 2005, the Boards of Directors of Soyland Power and Allegheny decided to end their business alliance. Downturns in the deregulation of the electric industry and limitations of regional market structures limited the economic advantages of the alliance. On May 13, 2006, the alliance was officially terminated and the new headquarters of Soyland was established in Jacksonville, Illinois. The transition went smoothly with the full cooperation of the staffs of Soyland and Allegheny.

In 2006, Soyland also paid off the last of the debit it restructured in 1996 and ended the year with an equity ratio of 18.50%. Today, Soyland is well positioned to face the future.

P.O. Box 13200
Grand Forks, ND 58208-3200

Main Telephone (701) 795-4000
Main FAX (701) 795-4215

Executive Contacts

General Manager	*David W. Loer*
Vice President, Finance and Administration	*Gary Spielman*
Vice President, Transmission	*Wallace Lang*
Vice President, Planning and System Operations	*Alvin Tschepen*
Vice President, Generation	*Luther Kvernen*
Vice President, Legal and Government Affairs	*David Sogard*

Accounting & Finance Related Personnel

Finance	*Gary Spielman*
Treasury	*Craig Rustad, Accounting Manager*
General Accounting	*Craig Rustad*
Property Accounting	*Craig Rustad*
Tax Accounting	*Craig Rustad*
Internal Auditing	*Craig Rustad*
Insurance - Plant	*Doug Gregoire - Human Resource Manager*
Data Processing	*Landis Hjelle - Information Systems Manager*
Employee Benefits	*Doug Gregoire*
Resource Planning	*Alvin Tschepen*

Ultimate Meters Served	N/A
REC Members	11
Other Firm Power Customers	0
Power Pool	N/AI
Total Plant Capacity	432 MW
# of Substations	1
Miles of Transmission Line	468
Total Employees	0 - See Minnkota
Union Employees	0
RUS Designation	ND 48

Taxable	Yes
State Regulated	No
Year Organized	1972
CPA - Tax	Brady, Martz
CPA - Audit	Brady, Martz

Corporate Insurance Providers

Worker's Comp	N/A
Primary Liability	Federated
Commercial Umbrella	Federated
Electric Property	FM Global

2006 Financial Keys

Total Assets	$359,537,035
Total Operating Revenue	$89,722,827
Net Margins	$1,749,970
Equity Ratio	6.29%
T.I.E.R.	1.09
DSC Ratio	1.12
Cost of Debt	6.26%

MW Peak Demands

Winter	N/A
Summer	N/A

2006 MWH Sales

Member	1,096,508 @ $27.71 per MWH
Non-Mem	2,093,335 @ $27.71 per MWH

Square Butte Electric Cooperative ("Square Butte") is a North Dakota cooperative corporation. It has as its Members, eleven rural electric distribution cooperatives which comprise the Class A Membership of Minnkota Power Cooperative, Inc. ("Minnkota"). The Members of Square Butte are engaged in the business of retailing electric power to approximately 95,000 consumers in eastern North Dakota and northwestern Minnesota. Square Butte is governed by a Board of Directors consisting of one representative from each of its members.

Square Butte was organized to finance and arrange for the construction and operation of a net 432 megawatt ("MW") steam electric generating unit ("Young No. 2") adjacent to the Milton R. Young Station near Center, North Dakota ("Young No. 1") presently owned and operated by Minnkota, and certain terminals and transmission lines (the "Transmission Facilities").

THE SQUARE BUTTE PROJECT

Young No. 2 commenced commercial operation in May, 1977, and is operated by Minnkota. Its fuel supply is North Dakota lignite purchased from BNI Coal, Ltd.

The Square Butte Project, in addition to Young No. 2, includes the Transmission Facilities: a 465 mile, ±250 kilovolt direct current ("DC") transmission line from the plant site near Duluth, Minnesota, a DC terminal located adjacent to Young No. 2 for converting the alternating current ("AC") from Young No. 2 into DC for transmission, and a DC terminal near Duluth, Minnesota, for converting the DC current back to AC.

POWER SALES AGREEMENT

Under the original Power Sales Agreement, MP&L was committed to purchase the entire output of Young No. 2 subject to election by Square Butte to retain certain amounts. Beginning in 1985, the Members of Square Butte elected to retain 126 MW or 30% of the 420 MW net capability of Young No. 2 and to sell this power to Minnkota. In 1991, the net capability of Young No. 2 was increased to 432 MW with Square Butte's retention remaining at 126 MW or 29.17% of the increased net capability. In May, 1998, Square Butte completed a lease buyout and executed new power sales agreements with Minnesota Power and Minnkota. Minnkota has options, with a two-year notice, to increase its share of Square Butte's net capability to a maximum of 50%. Minnkota has exercised these options.

JOINT OPERATING AGREEMENT

The Members of Square Butte also comprise the Class A Members of Minnkota. In addition to the Class A Members, Minnkota currently has five Class B Members and 17 Class C Members (including MP&L), which have no representatives on the Board of Directors of Minnkota. Square Butte shares the same office and administrative facilities as Minnkota. David W. Loer acts as the General Manager of Square Butte. Square Butte and Minnkota have entered into a joint operating agreement for the operation of Young No. 2. This agreement provides that all operating and maintenance costs of Young No. 1 and Young No. 2, except those which can be specifically identified, will be shared in the ratio of relative capacities of the two generating units. Expenses which can be identified will be paid by the party to which they relate (e.g., maintenance of the respective units). Since each party has its own coal contract, fuel costs are paid separately. The Joint Operating Agreement designates Minnkota as the operator who initially pays most operating and maintenance costs (exclusive of coal). Subsequently, Minnkota bills Square Butte for its share of the expenses Minnkota has paid on behalf of Square Butte.

COAL SUPPLY

Minnkota had the exclusive right to purchase lignite from BNI Coal, Ltd. Minnkota consented to a 50-year coal supply agreement between BNI Coal, Ltd. and Square Butte whereby BNI Coal, Ltd.,supplies the coal for Young No. 2 from its Center Mine.

301 West 13th
Hays, KS 67601

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Main FAX (785) 623-3395
www.sunflower.net

Executive Contacts

President, CEO	*L. Earl Watkins, Jr.*
Secretary, General Counsel	*Mark Calcara*
Executive Vice President, CFO	*Sidney J. Severson*
Senior Vice President, Administration	*James E. Hanks*
Vice President, Power Production & Engineering	*Kyle Nelson*
Vice President, Transmission Services & Engineering	*Noman L. Williams*
Executive Manager, Engineering/Energy Services	*Robert J. Johnson*
Executive Manager, Environmental Policy	*Wayne E. Penrod, Jr.*
Executive Manager, Financial Services	*Jayne E. Clarke*
Executive Manager, External Affairs	*Clare Gustin*
Executive Manager, Administrative Services	*Jana Horsfall*
Senior Manager, Power Production	*Steve Moss*
Senior Manager, External Affairs	*Stephen J. Miller*
Senior Manager, Corporate Security/Transmission O&M	*Keith Overland*
Senior Manager, Information Systems	*Jerry Herman*
Manager, Regulatory Relations	*Tom Hestermann*
Corporate Services Specialist	*Maree N. Percival*

Accounting & Finance Related Personnel

Cash Management	*Debbie Ball - Sr. Accountant*
Budget & General Accounting	*Jennifer Casper - Accountant*
Property & Tax Accounting	*Ralph Thummel -Accountant*
Financial Reporting	*Tory Molthan - Accountant*
Insurance - Plant	*Stephen J. Miller*

Ultimate Meters Served	53,463
REC Members	6
Other Firm Power Customers	3
Power Pool	MAPP, SPP, MOKAN
Total Plant Capacity	594 MW
# of Substations	29
Miles of Transmission Line	1,179
Total Employees	335
Union Employees	150
RUS Designation	KS 53
Taxable	Yes

State Regulated	Yes
Year Organized	1957
CPA - Tax	Deloitte & Touche, LLP
CPA - Audit	KPMG
Corporate Insurance Providers	
Worker's Comp	New Hampshire
Primary Liability	American Home Assur.
Commercial Umbrella	National Union Fire
Electric Property	Hartford Steam Boiler

2006 Financial Keys

Total Assets	$348,546,027
Total Operating Revenue	$140,835,920
Net Margins	$6,030,205
Equity Ratio	-19.06%
T.I.E.R.	1.32
DSC Ratio	1.23
Cost of Debt	0

MW Peak Demands

Winter	324
Summer	449

2006 MWH Sales

Member	1,892,244 @ $54.14 per MWH
Non-Mem	780,354 @ $42.14 per MWH

ORGANIZATION

Sunflower Electric Power Corporation is a generation and transmission (G&T) utility that operates as a non-profit corporation to produce and sell wholesale electric power. Sunflower was initially incorporated under the laws of the State of Kansas on August 2, 1957, as Sunflower Electric Cooperative, Inc. On May 19, 1989, Sunflower was reincorporated as a non-profit corporation to more closely align with business contacts. The name was changed to reflect its new corporate structure.

From 1957 to 1971, Sunflower was headquartered at WaKeeney, Kansas, and had no paid employees. In 1971, Sunflower moved its headquarters to Hays, Kansas, and the first paid employees were hired. In April 2007, Sunflower's Members acquired the Kansas Electric properties of an IOU that more than doubled the size of its members. A separate entity was formed for the purchase of the assets that included 608 MW of generation and 1,038 miles of transmission lines, as well as all of the distribution facilities. Sunflower has been contracted by the new entity, MKEC to provide operational support for the generation and transmission facilities of MKEC. Each Member owner of MKEC is operating and maintaining the distribution facilities. Sunflower has grown into an organization of 335 employees at Hays, Holcomb, Garden City, Great Bend, Dodge City and Colby, Kansas. Through its member RECs, Sunflower serves approximately 118,000 consumers in 34 western Kansas counties.

MEMBERSHIP

Sunflower was formed by six western Kansas rural electric cooperatives (RECs). The number of member RECs expanded in 1968 to eight, then was reduced to seven in January 1988, when the former Great Plains Electric Cooperative was acquired by Midwest Energy of Hays, Kansas. In January 1997, the number of members decreased to six when Northwest Kansas Electric Cooperative Association and Norton-Decatur Cooperative Electric Company merged to form Prairie Land Electric Cooperative. The current six member RECs are Lane-Scott Electric Cooperative, Pioneer Electric Cooperative, Prairie Land Electric Cooperative, Victory Electric Cooperative Association, Western Cooperative Electric Association and Wheatland Electric Cooperative.

MISSION

Sunflower people value, and expect one another to behave in ways that consistently exhibit the following characteristics: Technical Competency; Respect and Dignity; Trustworthiness; Integrity; Accountability and Servant Leadership.

We believe the consistent application of these core values in reaching the "best answer" in all cases will best enable us to fulfill our mission statement of providing reliable, long-term power supply and transmission services to our Member-Owners at the lowest possible cost consistent with sound business and cooperative principles.

POWER SUPPLY

Sunflower's 360 megawatt (MW) coal-fired base load generation plant is located near Holcomb. Sunflower's Garden City Complex has another 221 MW of generating capacity available in gas-fired peaking units and a 13 MW diesel cranked black start unit that can be used to bring the larger units back on line in the event of a system blackout.

TRANSMISSION

The transmission department and system control are also located at the Garden City Complex. Approximately 27 people work in the different departments. The transmission department maintains Sunflower's 222 miles of 345 KV line, 918 miles of 115 KV line, 74 miles of 69 KV line, substations, remote terminal units and microwave sites.

Tex La Electric Cooperative of Texas

P.O. Box 631623
Nacogdoches, TX 75963

Main Telephone (936) 560-9532
Main FAX (936) 560-9215

Executive Contacts

General Manager .... *Edd Hargett*
CFO .... *Ryan Thomas*

Ultimate Meters Served	156,424	Taxable	No
REC Members	7	State Regulated	No
Other Firm Power Customers	0	Year Organized	1979
Power Pool	N/A	CPA - Tax	Axley & Rode
Total Plant Capacity	0	CPA - Audit	Axley & Rode
# of Substations	10	**Corporate Insurance Providers**	
Miles of Transmission Line	90	Worker's Comp	Employers Mutual
Total Employees	7	Primary Liability	Employers Mutual
Union Employees	0	Commercial Umbrella	Employers Mutual
RUS Designation	TX 157	Electric Property	Travelers

2006 Financial Keys

Total Assets	$170,422,672
Total Operating Revenue	$88,916,048
Net Margins	$3,324,082
Equity Ratio	12.74%
T.I.E.R.	7.27
DSC Ratio	1.50
Cost of Debt	8.20%

MW Peak Demands

Winter	354
Summer	346

2006 MWH Sales

Member	1,427,281 @ $62.30 per MWH
Non-Mem	0

ORGANIZATION

Tex-La Electric Cooperative of Texas, Inc., was incorporated in 1979 as an electric generation and transmission cooperative. Tex-La provides wholesale electric service to its seven rural electric cooperative members.

MEMBERSHIP

Tex-La's Board of Directors is composed of two directors from each of the distribution cooperatives. One of the directors from each cooperative is the Manager of the Cooperative and the other is from the distribution cooperative's board of directors. The Board meets monthly.

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Tri-State G&T Association, Inc.

P.O. Box 33695
Denver, CO 80233-0695

Main Telephone (303) 452-6111
Main FAX (303) 254-6007
www.tristategt.org

Executive Contacts

Executive Vice President and General Manager	J.M. Shafer
Executive Assistant	Sharon Harkins
Senior Vice President Corporate Services	Mike McInnes
Senior Vice President Power Management/Generation	Ken Anderson
Senior Vice President Transmission	Joel Bladow
Senior Vice President and CFO	Charles L. Yetzbacher
Senior Vice President and General Counsel	Ken Reif
Senior Vice President External Affairs & Member Relations	Robert "Mac" McLennan
Vice President Environmental Services	Jerry Walker
Vice President Project Development	William Boyd

Accounting & Finance Related Personnel

Corporate Finance	Pat Bridges - Senior Manager Corporate Finance
Accounting, Joint Projects, Property, Tax	Steve Lindbeck - Senior Manager Controller
Treasury, A/P, Payroll	Ellen Connor - Senior Manager Financial Services
Financial Planning and Rates	Jim Spiers - Senior Manager Pricing and Forecasting
Resource Planning	Rob Wolaver - Senior Manager Energy Resources
Data Processing	Dan Ross - Senior Manager Information Technology
Risk Management	Howard Smith - Manager Safety & Insurance
Internal Auditing	Sherryl Caikowski - Manager Internal Audit
Employee Benefits	Jerry Jacobson - Manager Human Resources

Ultimate Meters Served	578,417
REC Members	44
Other Firm Power Customers	6
Power Pool	Inland Power Pool
Total Plant Capacity	2,451 MW
# of Substations	203
Miles of Transmission Line	5,096
Total Employees	1,029
Union Employees	316
RUS Designation	CO 47

Taxable	Yes
State Regulated	No
Year Organized	1952
CPA - Tax	Ernst & Young
CPA - Audit	Ernst & Young

Corporate Insurance Providers

Worker's Comp.	Self
Primary Liability	Federated
Commercial Umbrella	AEGIS & EIM
Electric Property	AEGIS

2006 Financial Keys

Total Assets	$2,471,415,634
Total Operating Revenue	$846,044,628
Net Margins	$45,928,154
Equity Ratio	15.12%
Debt Service Ratio	1.11
Cost of Debt	6.1%

MW Peak Demands

Winter	1,865
Summer	2,309

2006 MWH Sales

Member	13,094,448 @ $49.79 per MWH
Non-Mem	3,519,288 @ $53.13 per MWH

ORGANIZATION

Tri-State Generation and Transmission Association is a wholesale power supply cooperative that provides power to 44 member distribution systems that serve major parts of Colorado, Nebraska, New Mexico, and Wyoming. Tri-State was incorporated in 1952 by 26 systems and, in 1992, increased to 34 systems through the bankruptcy reorganization/ acquisition of Colorado-Ute Electric Association (member system mergers subsequently reduced the number of systems to 32). In 2000, Tri-State merged with Plains Electric Generation and Transmission Cooperative of Albuquerque, New Mexico and thereby increased its membership to 44 through the addition of 12 former Plains members.

Tri-State is governed by a Board of Directors, which is made up of one director from each of the 44 members.

In addition to serving its members, Tri-State sells a portion of its power to other utilities in the region under long-term contracts and spot sale arrangements.

MEMBERSHIP

Each of Tri-State's member utilities is a nonprofit organization owned by the consumers it serves and is directed by a board made up of consumers in its service area. The combined 44-member distribution system supplies electricity to 578,417 consumer meters serving a member population of 1.4 million throughout a 250,000 square mile service area.

Tri-State has all-requirements contracts with all of its members whereby each member will receive continued electricity service from Tri-State through the year 2040.

POWER SUPPLY

Tri-State's owned and contracted energy mix amounts to about 3,510 megawatts of capacity. Tri-State is the operating agent for Craig Station, a 1,274-megawatt coal-fired power plant in northwestern Colorado. The Association receives 624 megawatts from its 24% ownership of Units 1 and 2 and its lease of the 418-megawatt Unit 3. In 2006, Tri-State acquired the remaining 22% equity ownership interests in the Craig Generating Station Unit 3 lease in two separate transactions. These purchases plus the 70% and 8% acquired in 2004 and 2002, respectively, bring the total equity ownership interests in Unit 3 to 100%.

In the merger with Plains, Tri-State became owner and operator of the Escalante Station, which is a 245-megawatt, coal-fired power plant near Prewitt, New Mexico. The 100-megawatt, coal-fired Nucla Station in southwestern Colorado, which features an innovative circulating fluidized-bed combustion technology, is wholly owned and operated by Tri-State. The Association owns 24%, or 399 megawatts, of the 1,650-megawatt coal-fired Laramie River Station near Wheatland, Wyoming, which is operated by Basin Electric Power Cooperative. Tri-State also owns 8.2%, or 40 megawatts, of the coal-fired San Juan Generating Station's Unit 3 near Farmington, New Mexico. In 2003, Tri-State closed on a transaction in which it acted as the construction agent for the construction of a 418-megawatt, coal-fired generating unit in Arizona on behalf of the owner lessor. In July 2006, construction was completed and the lease commenced. Tri-State is leasing the Springerville Unit 3 facility from the owner lessor through a 34-year operating lease. In addition, Tri-State has five combustion turbine plants in Colorado and New Mexico with a combined capacity of 625 megawatts.

The balance of Tri-State's power resources is purchased from other suppliers, primarily the Western Area Power Administration and Basin Electric Power Cooperative, of which Tri-State is a member. Tri-State purchases a small, but growing, amount of energy from renewable energy sources such as wind and methane gas projects.

TRANSMISSION

High-voltage electricity is delivered to the member systems over a network of 5,096 miles of transmission line, 203 substations and switching stations, and the David A. Hamil D.C. tie near Stegall, Nebraska.

FINANCIAL RATINGS INFORMATION

Standard and Poor's ... A
Fitch ... A
Moody's ... Baa2
(Baa1 if secured under the Indenture)

Upper Missouri G&T

P.O. Box 1069
Sidney, Montana 59270

Main Telephone (406) 433-4100
Main FAX (406) 433-4105

Executive Contacts

Manager..*Tom Barnett*

Ultimate Meters Served	40,406	Taxable	Yes
REC Members	9	State Regulated	No
Other Firm Power Customers	1	Year Organized	1957
Power Pool	N/A	CPA - Tax	Brenner, Averett & Co., PC
Total Plant Capacity	0	CPA - Audit	Brenner, Averett & Co., PC
# of Substations	10	**Corporate Insurance Providers**	
Miles of Transmission Line	174.24	Worker's Comp	Federated
Total Employees	2	Primary Liability	Federated
Union Employees	None	Commercial Umbrella	Federated
RUS Designation	MT 40	Electric Property	Federated

2006 Financial Keys

Total Assets	$30,258,136
Total Operating Revenue	$45,042,736
Net Margins	$2,498,263
Equity Ratio	53.65%
T.I.E.R.	5.41
DSC Ratio	
Cost of Debt	6.76

Peak Demands

Winter	272
Summer	228

2006 MWH Sales

Member .....1,392,126 @ $27.05 per MWH
Non-Mem .....244,888 @ $30.15 per MWH

ORGANIZATION

Upper Missouri G&T Electric Cooperative, Inc. was formed in 1957 with an eleven member system as the original founders. Currently we serve ten distribution cooperatives, nine as members. Upper Missouri's board of directors consists of a representative from each member cooperative that we serve.

We have two major power suppliers: Basin Electric Power Cooperative and Western Area Power Administration. Through the distribution systems, we serve approximately 12,159 consumers in all or part of 14 eastern Montana counties and approximately 28,247 consumers in all or part of 16 western North Dakota counties. We own or operate, through the distribution cooperatives, 1,080 miles of transmission lines of varying voltages.

Headquartered in Sidney, Montana, Upper Missouri G&T is small but efficient, operating with two employees. We are proud to be celebrating 50 years in business.

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P.O. Box 24700
Indianapolis, Indiana 46224

Main Telephone (317) 481-2800
Main FAX (317) 243-6416
www.wvpa.com

Executive Contacts

President and Chief Executive Officer	Rick D. Coons
Executive Assistant	Adrienne Kalkhoff
Vice President, Power Supply	Lee Wilmes
Vice President, Power Production	Keith Thompson
Vice President, Technical Services	Cathy L. Ellis
Vice President, Administration	Kathy Joyce
Chief Financial Officer	Jeff Conrad

Accounting & Finance Related Personnel

Finance	Nisha Harke—Manager, Finance and Rates
Treasury	Denise Sewell - Accounting Principal
General Accounting	Theresa Young - Controller
Property Accounting	Jo Suttle—Financial Accountant
Tax Accounting	Lisa Badger—Financial Analyst-Accounting
Internal Auditing	N/A
Insurance - Plant	Marvin Gwin—Financial Analyst-Joint Ownership
Data Processing	Cathy L. Ellis—Vice President, Technical Services
Employee Benefits	Denne' Smith—Compensation/Benefits Administrator
Resource Planning	Lee Wilmes - Vice President, Power Supply

Ultimate Meters Served	364,754
REC Members	28
Other Firm Power Customers	0
Power Pool	N/A
Total Plant Capacity	425 MW
# of Substations	55
Miles of Transmission Line	413
Total Employees	61
Union Employees	0
RUS Designation	IN 107

Taxable	No
State Regulated	Yes
Year Organized	1963
CPA - Tax	N/A
CPA - Audit	Deloitte & Touche

Corporate Insurance Providers

Worker's Comp.	
Primary Liability	Chubb
Commercial Umbrella	Chubb
Electric Property	Chubb

2006 Financial Keys

Total Assets	$488,407,378
Total Operating Revenue	$569,041,251
Net Margins	$4,000,000
Equity Ratio	12.23%
T.I.E.R.	1.23
DSC Ratio	1.24
Cost of Debt	5.33%

MW Peak Demands

Winter	1,265
Summer	1,522

2006 MWH Sales

Member	8,338,572 @ $49.12 per MWH
Non-Mem	3,480,484 @ $42.39 per MWH

ORGANIZATION

In 1963, a few rural electric cooperatives formed Wabash Valley Power for better leverage in negotiating long-term, low-cost wholesale power supply contracts. Since then, we've grown to a membership of 28 rural electric cooperatives. We generate, purchase, and transmit wholesale power to our members, who in turn distribute the retail power to their 365,000 consumer-owners. Wabash Valley exists to supply and deliver reliable wholesale power at a stable and competitive price to its Member-Owners and respond to their collective needs.

MEMBERSHIP

Wabash Valley's Board of Directors consists of one representative from each of its members. Wabash Valley has 2 members that are not cooperatives; J. Aron and Wabash Valley Energy Marketing.

POWER SUPPLY

Wabash Valley Power has a 25% ownership of Gibson Unit 5, a 625-MW coal-fired unit located in southern Indiana. Wabash Valley has 50% ownership in a gasification plant that provides steam and synthetic gas to fuel the 260-MW Wabash River Unit 1. Wabash Valley Power plans to acquire Wabash River Unit 1 from Duke Energy Indiana by the end of 2007. Wabash Valley also owns 22-MW of landfill gas generation and 260-MW of gas-fired peaking power. A portfolio of purchase power agreements is used to satisfy the rest of Wabash Valley Power's load requirements.

TRANSMISSION

Wabash Valley Power's service territory encompasses 50 Indiana counties, 6 Michigan counties, 30 Illinois counties and 4 Missouri counties. Wabash Valley has 413 miles of transmission and 55 substations.

REGULATION

Wabash Valley Power is regulated by the Federal Energy Regulatory Commission for rate-related matters. The Indiana Utility Regulatory Commission has jurisdiction on financings and certain asset acquisitions.

OTHER POINTS OF INTEREST

In May 2006, Wabash Valley's board approved the membership of Citizens Electric corporation (Citizens). Citizens is located in Missouri, and began taking power from Wabash Valley Power on January 1, 2007. Citizens is Wabash Valley's 28th cooperative member.

FINANCIAL RATING INFORMATION

Wabash Valley has a BBB+ credit rating with a stable outlook from Standard & Poor's.

P.O. Box 429
Anadarko, OK 73005

Main Telephone (405) 247-3351
Main FAX (405) 247-4444
www.wfec.com

Executive Contacts

Chief Executive Officer	*Gary R. Roulet*
Executive Administrator	*JoAnn Parker*
Treasurer & Financial Risk Officer	*Ron Cunningham*
General Manager, Transmission & Distribution	*Ron Cunningham*
General Manager, Power Production	*Bob Orme*
Chief Financial Officer	*Jane Lafferty*
General Manager, Marketing & Communications	*Jim O'Neill*
General Manager, Legal & Administration	*Brian Hobbs*

Accounting & Finance Related Personnel

Finance	*Jane Lafferty*
Treasury	*Jane Lafferty*
General Accounting	*Robert Elrod - Manager, Financial Services*
Property Accounting	*Tom Blanchard - Financial Systems Supv.*
Tax Accounting	*Larry Arthur - Tax & Internal Control Accountant*
Internal Auditing	*Larry Arthur*
Insurance - Plant	*Brian Hobbs*
Data Processing	*Howard Fleshman - Manager, Information Services*
Employee Benefits	*Rodney Palesano - Manager, Human Resources*
Resource Planning	*John Toland - Principal Production Engineer*

Ultimate Meters Served	258,130
REC Members	19
Other Firm Power Customers	8
Power Pool	SPP
Total Plant Capacity	1,128 MW
# of Substations	256
Miles of Transmission Line	3,622
Total Employees	357
Union Employees	0
RUS Designation	OK 32

Taxable	Yes
State Regulated	No
Year Organized	1941
CPA - Tax	PricewaterhouseCoopers LLP
CPA - Audit	KPMG LLP
Corporate Insurance Providers	
Worker's Comp.	Self-Insured
Primary Liability	Self-Insured
Commercial Umbrella	AEGIS
Electric Property	FM Global

2006 Financial Keys

Total Assets	$780,728,459
Total Operating Revenue	$402,149,402
Net Margins	$10,355,377
Equity Ratio	11.95%
T.I.E.R.	1.33
DSC Ratio	1.11
Cost of Debt	6.06%

MW Peak Demands

Winter	1,248
Summer	1,409

2006 MWH Sales

Member	6,250,641 @ $58.39 per MWH
Non-Mem	423,452 @ $55.98 per MWH

ORGANIZATION

Headquartered in Anadarko, Oklahoma, WFEC is a generation and transmission cooperative incorporated in 1941 under the laws of the state of Oklahoma. Supplying the electrical needs of more than two-thirds of rural Oklahoma, WFEC delivers wholesale electric power to 19 member systems and a United States Air Force base. The member systems, in turn, service the electrical power needs of more than a half million people. WFEC also sells electricity to eight municipalities.

MEMBERSHIP

WFEC's 20-member Board of Trustees consists of one representative from each of its member-owners. This Board meets monthly and sets policy and wholesale electric rates for its members.

POWER SUPPLY

WFEC has generation plants located in Anadarko, Mooreland, and Hugo, Oklahoma. The Anadarko Plant consists of six units - three are conventional steam boilers and three are combined-cycle gas turbines, with a combined capacity of 374 MW. The Mooreland Plant, with 304 MW, generates with three conventional steam boilers, and the Hugo Plant is a 450 MW coal-fired facility. In addition, WFEC has long-term power contracts to purchase 260 MW of hydropower from Southwestern Power Administration and all of the energy produced from the 74 MW Blue Canyon wind farm.

TRANSMISSION

High-voltage electricity is delivered to the member systems throughout a network of transmission lines, substations, and switch station facilities located around the state and in parts of Texas and Kansas. WFEC transmission is included in the Southwest Power Pool Regional Tariff. WFEC operates a control area transmission center, a telecommunications system, and a supervisory control and data acquisition (SCADA) system.

OTHER POINTS OF INTEREST

WFEC was formed as a tax-exempt non-profit electric cooperative to provide a reliable cost-based supply of power to its members. However, WFEC received a private letter ruling in 1982 to become a taxable entity, which allowed the Cooperative to benefit from the Safe Harbor Leasing provisions on its coal-fired Hugo Plant.

One of WFEC's wholly owned for-profit subsidiaries constructed and maintains a 14-mile railroad. This facility provides WFEC with access to alternate rail supply routes for coal delivery from Wyoming to the Hugo Plant near Fort Towson, Oklahoma.

During 2001, through another subsidiary, construction of two 45-megawatt simple cycle generating facilities, fueled by natural gas, was completed in Anadarko, Oklahoma. An agreement was entered into with another party to purchase the capacity of these units. The agreement contains certain recall provisions allowing recall of capacity at certain intervals. 30 MW's have been recalled for use by WFEC.

A contributing asset is the Cooperative's transmission gas pipeline with intrastate and interstate pipeline interconnections providing access to several gas marketing organizations and gas supply sources. *The pipeline delivers* fuel to the Mooreland and Anadarko Plants.

In Oklahoma, retail competition has been stalled for several years, following the passage of SB 440 by the state Legislature in 2001, which called for further study of the issue. A report was submitted to the governor and the Legislature in late 2002. There has been no new action on the issue until early in 2007 when SB 734 was introduced, which proposes to create a Joint Electric Utility Restructuring Task Force to study certain issues relating to retail electric consumer choice in Oklahoma.

WFEC is a Regional Partner in Touchstone Energy and an equity owner of ACES Power Marketing. Its financial ratings affirmed by Standard & Poor's and Fitch are BBB+ and A–, respectively.

Western Montana Electric Generating and Transmission Cooperative, Inc.

1001 SW Higgins
Panorama Park, Suite 206
Missoula, Montana 59803-1340

Main Telephone (406) 721-0945
Main FAX (406) 721-3738

Executive Contacts

Manager.. *William K. Drummond*
Executive Assistant .... *Cathy Schwenk*

DESCRIPTION

The Western Montana Electric Generating and Transmission Cooperative (WMG&T), provides power planning and representation for its seven members; six rural cooperatives and one tribal utility in Montana. WMG&T's members serve over 100,000 electric consumers. WMG&T offers power and transmission contract negotiation and administration, policy analysis and lobbying services to its members. WMG&T also provides consulting services to publicly-owned utilities.

The WMG&T members in western Montana purchase the majority of their power requirements from the Bonneville Power Administration. The members of WMG&T are: **Flathead Electric Cooperative**; Kalispell, Montana, **Glacier Electric Cooperative**; Cut Bank, Montana, **Lincoln Electric Cooperative**; Eureka, Montana, **Missoula Electric Cooperative**; Missoula, Montana, **Mission Valley Power**; Pablo, Montana, **Ravalli County Electric Cooperative**; Corvallis, Montana, **Vigilante Electric Cooperative**; Dillon, Montana.

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P.O. Box 229
Cadillac, Michigan 49601

Main Telephone (231) 775-5700
Main FAX (231) 775-2077
www.wpsci.com

Executive Contacts

President & Chief Executive Officer	*Eric D. Baker*
Executive Vice President	*Craig Borr*
Staff Attorney	*Brian Valice*
Vice President of Power Supply & Energy Control	*Pete Chase*
Vice President of Engineering & Operations	*Danny Janway*
Vice President of Accounting & Finance	*Richard Kehl*
Vice President of Human Resources	*Craig Borton*
Vice President of Generation	*Dan DeCoeur*
Vice President of Rates & Administrative Services	*Kim Molitor*

Accounting & Finance Related Personnel

Finance	*Richard Kehl*
Treasury	*Richard Kehl*
General Accounting	*Richard Kohler - Accounting Supervisor*
Corp. Property & Liability Insurance	*Richard Kehl*
Data Processing, Information Services	*Jeff Brooks*
Employee Benefits, Human Resources	*Craig S. Borton*
Resource Planning	*Eric Baker*

Ultimate Meters Served (Approx)	210,763
REC Members	4
Other Firm Power Customers	2
Power Pool	ECAR
Total Plant Capacity	237 MW
# of Substations	176
Miles of Transmission Line	1,600
Total Employees	104
Union Employees	46
RUS Designation	N/A

Taxable	No
State Regulated	No
Year Organized	1983
CPA - Tax	N/A
CPA - Audit	Plante & Moran, LLP

Corporate Insurance Providers

Worker's Comp	Accident Fund Co.
Excess Liability	AEGIS
Electric Property	Ace American Ins. Co.

2006 Financial Keys

Total Assets	$223,598,350
Total Operating Revenue	$195,689,229
Net Margins	$17,886,655
Equity Ratio	47.46%
T.I.E.R.	4.30
DSC Ratio	
Cost of Debt	5.48%

MW Peak Demands

Winter	406
Summer	486

2006 MWH Sales

Member	3,120,623 @ N/A per MWH
Non-Mem	243,361 @ N/A per MWH

ORGANIZATION

Wolverine Power Supply Cooperative, Inc., is a G&T cooperative incorporated under the laws of the State of Michigan, with Headquarters in Cadillac, Michigan. Wolverine provides wholesale power to six member cooperatives that provide retail energy services to nearly 600,000 member-customers throughout Michigan. Wolverine is non-taxable as defined under Section 501 (c) (12) of the Internal Revenue Code. Wolverine is regulated by the Federal Energy Regulatory Commission (FERC) and receives all of its financing from the National Rural Utilities Cooperative Finance Corporation (CFC).

MEMBERSHIP

Six member cooperatives comprise Wolverine Power Supply Cooperative. Wolverine is governed by a 12-member board of directors.

POWER SUPPLY

Wolverine is presently purchasing energy and capacity, on both a long and short term basis, from a variety of both in-state and out-state supplier that include investor-owned utilities, power marketers and others. Wolverine owns and operates approximately 237 megawatts of internal generation, which is primarily used as peaking capacity. Wolverine also owns approximately 15 MW of the J.H. Campbell III coal fired plant, owned by Consumers Energy Company.

Purchases, scheduling, trading and transmission functions are monitored through Wolverine's Energy Control Center located adjacent to the cooperative's offices in Cadillac. Wolverine owns and operates approximately 1,600 miles of transmission line and more than 176 transmission and distribution substations. In 2006, Wolverine sold nearly 3.36 million MWH of energy and had a peak demand of 486 MW.

SERVICE AREA CHARACTERISTICS

The majority of the member-cooperatives' retail sales are attributable to residential customers. Although seasonal member-customers comprise nearly 1/3 of the total customer base, less than 10% of overall sales are attributable to this customer class. Commercial and industrial customers comprise the remaining approximately 25% of energy sold by Wolverine's member-cooperatives.

2006 - Total MWh Sales

1	23,025,710	Oglethorpe
2	22,397,441	Associated
3	17,968,000	Basin
4	17,006,749	Seminole
5	16,613,736	Tri-State
6	16,476,547	North Carolina
7	14,665,444	Great River
8	13,492,954	Central Electric - SC
9	13,075,407	Arkansas
10	12,206,412	East Kentucky
11	11,819,056	Wabash Valley
12	11,530,377	Brazos
13	9,923,558	Hoosier
14	9,535,462	South Mississippi
15	9,498,411	Alabama
16	8,231,237	Buckeye
17	6,674,093	Western Farmers
18	6,477,751	Golden Spread
19	6,118,651	Dairyland
20	5,860,754	KAMO
21	5,575,711	Deseret
22	5,250,342	Big Rivers
23	5,212,481	PNGC Power
24	4,005,648	Saluda River
25	3,969,952	Minnkota
26	3,923,837	Sho-Me Power
27	3,499,705	Nebraska
28	3,490,774	Arizona
29	3,363,984	Wolverine
30	3,253,019	Central Electric - MO
31	3,189,843	Square Butte
32	3,024,070	Northeast Texas
33	2,952,198	Allegheny
34	2,937,194	San Miguel
35	2,929,158	Rayburn Country
36	2,753,266	Chugach
37	2,672,598	Sunflower
38	2,451,023	Central Iowa
39	2,408,994	East River
40	2,332,883	South Texas
41	2,214,165	Southern Illinois
42	1,794,728	Kansas Electric
43	1,759,562	Corn Belt
44	1,682,331	Sam Rayburn
45	1,637,014	Upper Missouri
46	1,599,342	M & A Electric
47	1,555,262	N. W. Electric
48	1,492,128	Soyland
49	1,454,767	Central Power - ND
50	1,427,281	Tex-La
51	1,214,901	Northwest Iowa
52	1,174,604	Northeast Missouri
53	930,944	Rushmore
54	417,422	Central Montana
55	262,087	Power Resources

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Total Revenue per MWh

1	27.52	Upper Missouri
2	27.71	Square Butte
3	30.71	Northwest Iowa
4	31.41	Rushmore
5	31.93	PNGC Power
6	32.67	East River
7	32.86	Central Power - ND
8	34.31	Basin
9	34.35	San Miguel
10	35.42	Central Electric - MO
11	35.53	Northeast Missouri
12	35.69	M & A Electric
13	36.35	Big Rivers
14	37.47	N. W. Electric
15	37.96	Nebraska
16	38.31	KAMO
17	38.62	Associated
18	38.80	Minnkota
19	39.11	Saluda River
20	39.23	Deseret
21	39.77	Sho-Me Power
22	41.84	Buckeye
23	44.46	Hoosier
24	45.02	Dairyland
25	45.23	Corn Belt
26	46.28	Arkansas
27	46.78	Great River
28	47.13	Wabash Valley
29	49.03	Oglethorpe
30	50.50	Tri-State
31	50.63	Sunflower
32	53.16	East Kentucky
33	53.71	Northeast Texas
34	54.99	Southern Illinois
35	55.20	Allegheny
36	55.27	North Carolina
37	56.04	Soyland
38	56.20	Sam Rayburn
39	56.54	Central Iowa
40	57.49	Central Electric - SC
41	57.75	Western Farmers
42	57.83	South Texas
43	58.17	Wolverine
44	61.72	Kansas Electric
45	62.30	Tex-La
46	64.10	Power Resources
47	64.81	Alabama
48	66.40	South Mississippi
49	67.32	Golden Spread
50	68.48	Seminole
51	74.03	Brazos
52	77.72	Rayburn Country
53	97.17	Chugach

The Membership Average for this Ranking is: 48.66

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Member MWh Sales

1	23,019,482	Oglethorpe
2	17,336,688	Associated
3	16,777,086	Seminole
4	15,125,412	North Carolina
5	13,492,954	Central Electric - SC
6	13,094,448	Tri-State
7	12,129,402	East Kentucky
8	12,018,796	Arkansas
9	11,849,000	Basin
10	11,421,473	Great River
11	11,363,383	Brazos
12	9,528,089	South Mississippi
13	8,590,026	Alabama
14	8,338,572	Wabash Valley
15	7,904,419	Buckeye
16	6,525,739	Hoosier
17	6,250,641	Western Farmers
18	5,860,754	KAMO
19	5,463,467	Dairyland
20	4,923,961	Golden Spread
21	3,955,380	PNGC Power
22	3,499,705	Nebraska
23	3,336,119	Arizona
24	3,253,019	Central Electric - MO
25	3,208,788	Saluda River
26	3,188,056	Big Rivers
27	3,120,623	Wolverine
28	3,080,882	Minnkota
29	3,024,070	Northeast Texas
30	2,937,194	San Miguel
31	2,929,158	Rayburn Country
32	2,833,858	Allegheny
33	2,744,628	Sho-Me Power
34	2,451,023	Central Iowa
35	2,408,994	East River
36	2,188,796	South Texas
37	2,075,361	Deseret
38	1,892,244	Sunflower
39	1,883,652	Southern Illinois
40	1,790,777	Kansas Electric
41	1,713,003	Corn Belt
42	1,682,331	Sam Rayburn
43	1,599,342	M & A Electric
44	1,555,262	N. W. Electric
45	1,523,289	Chugach
46	1,492,128	Soyland
47	1,454,767	Central Power - ND
48	1,427,281	Tex-La
49	1,392,126	Upper Missouri
50	1,174,604	Northeast Missouri
51	1,096,508	Square Butte
52	955,835	Northwest Iowa
53	930,944	Rushmore

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Member Revenue Per MWh

1	27.05	Upper Missouri
2	27.71	Square Butte
3	30.44	PNGC Power
4	30.73	Basin
5	31.41	Rushmore
6	32.67	East River
7	32.71	Northwest Iowa
8	32.77	Associated
9	32.86	Central Power - ND
10	34.11	Big Rivers
11	34.35	San Miguel
12	35.42	Central Electric - MO
13	35.53	Northeast Missouri
14	35.69	M & A Electric
15	35.80	Minnkota
16	37.47	N. W. Electric
17	37.96	Nebraska
18	38.31	KAMO
19	38.92	Deseret
20	40.20	Sho-Me Power
21	41.59	Buckeye
22	44.52	Great River
23	45.68	Corn Belt
24	46.37	Dairyland
25	46.59	Saluda River
26	47.85	Arkansas
27	48.98	Oglethorpe
28	49.12	Wabash Valley
29	49.65	Hoosier
30	49.79	Tri-State
31	53.22	East Kentucky
32	53.71	Northeast Texas
33	54.14	Sunflower
34	56.04	Soyland
35	56.12	North Carolina
36	56.20	Sam Rayburn
37	56.54	Central Iowa
38	56.54	Southern Illinois
39	56.90	Allegheny
40	57.49	Central Electric - SC
41	58.39	Western Farmers
42	58.64	South Texas
43	61.82	Kansas Electric
44	62.30	Tex-La
45	64.98	Alabama
46	68.16	South Mississippi
47	68.59	Seminole
48	69.44	Golden Spread
49	72.26	Chugach
50	75.84	Brazos

The Membership Average for this Ranking is: 47.39

Note: Member Information Excluded if No Data Available or Category N/A

2006 - MWh's Generated

1	21,272,913	Oglethorpe
2	16,711,718	Basin
3	14,020,387	Associated
4	11,978,676	Tri-State
5	11,737,009	Seminole
6	11,197,632	East Kentucky
7	11,114,995	Great River
8	9,986,125	Arkansas
9	8,164,431	Hoosier
10	7,431,840	Buckeye
11	5,991,268	Dairyland
12	5,929,124	Alabama
13	4,752,428	North Carolina
14	4,522,656	Deseret
15	4,485,059	Brazos
16	4,344,022	Western Farmers
17	4,167,465	South Mississippi
18	3,189,843	Square Butte
19	2,937,194	San Miguel
20	2,844,017	Arizona
21	2,500,097	Sunflower
22	2,424,985	Chugach
23	2,157,118	Central Iowa
24	2,034,867	Southern Illinois
25	1,861,278	Allegheny
26	1,677,207	Minnkota
27	1,583,829	Saluda River
28	1,368,992	Wabash Valley
29	1,238,283	Golden Spread
30	1,214,968	Corn Belt
31	805,514	Northeast Texas
32	561,145	Kansas Electric
33	550,007	South Texas
34	372,959	Sam Rayburn
35	279,350	Power Resources
36	259,066	Northwest Iowa
37	167,389	Soyland
38	112,873	Wolverine
39	783	Sho-Me Power

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Cost per MWh Generated

1	18.07	Northwest Iowa
2	23.27	Minnkota
3	23.39	Buckeye
4	23.86	Wabash Valley
5	24.41	Square Butte
6	26.64	Deseret
7	27.11	Basin
8	28.42	Hoosier
9	29.73	Dairyland
10	31.00	Allegheny
11	31.47	Great River
12	32.13	Arkansas
13	32.86	Corn Belt
14	34.22	Associated
15	34.44	San Miguel
16	35.69	Central Iowa
17	36.85	Northeast Texas
18	37.11	Sunflower
19	37.28	Southern Illinois
20	37.96	Tri-State
21	38.20	Sam Rayburn
22	39.92	Soyland
23	41.59	Power Resources
24	42.35	East Kentucky
25	42.44	North Carolina
26	43.16	Oglethorpe
27	43.82	Kansas Electric
28	48.00	Seminole
29	52.24	Western Farmers
30	53.70	South Mississippi
31	53.88	Alabama
32	63.91	Chugach
33	72.82	Golden Spread
34	78.65	Wolverine
35	104.92	South Texas

The Membership Average for this Ranking is: 40.73

Note: Member Information Excluded if No Data Available or Category N/A

2006 - MWh's Purchased

1	13,831,632	Central Electric - SC
2	11,930,444	North Carolina
3	10,824,749	Wabash Valley
4	9,586,547	Associated
5	7,293,535	Brazos
6	5,867,169	KAMO
7	5,865,889	Tri-State
8	5,616,485	Seminole
9	5,546,728	South Mississippi
10	5,332,116	Golden Spread
11	5,294,138	Big Rivers
12	5,271,977	PNGC Power
13	4,358,360	Great River
14	3,924,512	Sho-Me Power
15	3,876,372	Alabama
16	3,523,420	Arkansas
17	3,499,705	Nebraska
18	3,361,079	Wolverine
19	3,253,019	Central Electric - MO
20	3,001,151	Rayburn Country
21	2,538,414	Minnkota
22	2,537,359	Saluda River
23	2,508,658	Western Farmers
24	2,432,000	East River
25	2,308,686	Northeast Texas
26	2,108,654	Oglethorpe
27	1,983,398	Hoosier
28	1,926,426	Basin
29	1,910,259	South Texas
30	1,637,014	Upper Missouri
31	1,599,342	M & A Electric
32	1,556,034	N. W. Electric
33	1,523,645	East Kentucky
34	1,511,823	Central Power - ND
35	1,478,873	Tex-La
36	1,402,451	Sam Rayburn
37	1,341,564	Soyland
38	1,301,708	Kansas Electric
39	1,221,379	Allegheny
40	1,213,046	Deseret
41	1,175,563	Northeast Missouri
42	1,049,703	Buckeye
43	985,950	Northwest Iowa
44	930,944	Rushmore
45	692,018	Arizona
46	597,712	Corn Belt
47	475,909	Chugach
48	427,972	Central Iowa
49	407,889	Dairyland
50	384,629	Southern Illinois
51	323,418	Sunflower

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Cost Per MWh Purchased

1	16.10	Allegheny
2	20.67	Big Rivers
3	20.78	Buckeye
4	25.80	East River
5	25.90	Central Power - ND
6	25.97	Upper Missouri
7	26.40	Northwest Iowa
8	27.06	PNGC Power
9	29.73	Rushmore
10	30.90	Northeast Missouri
11	31.39	Associated
12	31.68	N. W. Electric
13	32.12	Sho-Me Power
14	32.24	M & A Electric
15	32.42	KAMO
16	32.52	Central Electric - MO
17	32.56	Soyland
18	32.61	South Texas
19	35.96	Minnkota
20	36.29	Wabash Valley
21	37.16	Tri-State
22	37.96	Nebraska
23	39.58	Basin
24	39.71	Southern Illinois
25	40.83	Corn Belt
26	41.53	Great River
27	41.75	Wolverine
28	42.75	Deseret
29	44.86	Western Farmers
30	46.76	Saluda River
31	47.19	Central Iowa
32	49.97	East Kentucky
33	50.30	Arizona
34	51.69	Sunflower
35	51.90	Chugach
36	52.44	Northeast Texas
37	53.14	North Carolina
38	53.26	Hoosier
39	54.74	Central Electric - SC
40	54.85	Sam Rayburn
41	54.87	Dairyland
42	55.36	Alabama
43	56.35	Kansas Electric
44	57.18	Arkansas
45	57.48	Tex-La
46	58.47	Golden Spread
47	60.64	South Mississippi
48	73.70	Rayburn Country
49	84.95	Oglethorpe
50	93.48	Seminole

The Membership Average for this Ranking is: 43.28

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Number of Employees

1	1,123	Basin
2	1,029	Tri-State
3	768	Great River
4	637	Associated
5	620	East Kentucky
6	598	Dairyland
7	542	Alabama
8	484	Seminole
9	463	Hoosier
10	357	Western Farmers
11	354	Brazos
12	348	Chugach
13	338	Minnkota
14	335	Sunflower
15	283	South Mississippi
16	242	Sierra Southwest
17	237	Georgia
18	218	Arkansas
19	183	San Miguel
20	176	South Texas
21	161	Oglethorpe
22	149	North Carolina
23	149	Sho-Me Power
24	143	Deseret
25	120	Central Electric - MO
26	118	Southern Illinois
27	110	Central Iowa
28	104	East River
29	104	Wolverine
30	104	Big Rivers
31	95	Corn Belt
32	61	Wabash Valley
33	58	Soyland
34	57	Northeast Missouri
35	56	N. W. Electric
36	55	Allegheny
37	45	Northwest Iowa
38	43	M & A Electric
39	42	Southwest Transmission
40	39	New Horizon
41	37	Central Power - ND
42	36	PNGC Power
43	35	Central Electric - SC
44	32	Buckeye
45	24	Kansas Electric
46	21	Rushmore
47	19	Arizona
48	16	KAMO
49	10	Golden Spread
50	7	Sam Rayburn
51	7	Tex-La
52	6	Rayburn Country
53	4	Nebraska
54	2	Northeast Texas
55	2	Upper Missouri
56	2	Central Montana

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Total Assets

1	4.901.745.000	Oglethorpe
2	2.879.776.889	Basin
3	2.471.415.634	Tri-State
4	2.028.501.182	East Kentucky
5	1.980.916.000	Great River
6	1.821.765.076	Associated
7	1.493.901.731	Brazos
8	1.410.567.844	Seminole
9	1.307.077.135	North Carolina
10	1.254.388.832	Big Rivers
11	1.199.933.625	Alabama
12	1.117.608.500	Arkansas
13	1.042.444.450	Hoosier
14	1.011.163.017	South Mississippi
15	945.788.755	Dairyland
16	923.957.611	Buckeye
17	790.728.459	Western Farmers
18	563.040.148	Chugach
19	488.407.378	Wabash Valley
20	474.944.836	Deseret
21	462.198.104	Central Iowa
22	404.848.990	KAMO
23	360.495.996	Allegheny
24	359.537.035	Square Butte
25	348.546.027	Sunflower
26	341.795.877	Southern Illinois
27	341.107.480	Golden Spread
28	335.644.754	South Texas
29	308.028.349	Corn Belt
30	279.561.295	Arizona
31	261.235.992	Sho-Me Power
32	229.949.694	San Miguel
33	229.922.952	Northeast Texas
34	223.598.350	Wolverine
35	206.481.413	Minnkota
36	206.069.092	Kansas Electric
37	193.755.837	Central Electric - SC
38	193.552.854	Central Electric - MO
39	181.601.804	East River
40	170.422.672	Tex-La
41	166.847.566	Saluda River
42	120.032.300	N. W. Electric
43	106.503.137	Southwest Transmission
44	88.351.615	New Horizon
45	85.287.830	M & A Electric
46	84.224.676	Soyland
47	78.115.620	Rayburn Country
48	67.247.345	Central Power - ND
49	65.981.341	Northwest Iowa
50	62.412.711	Sam Rayburn
51	60.863.369	Northeast Missouri
52	36.657.744	PNGC Power
53	35.823.279	Power Resources
54	30.258.136	Upper Missouri
55	25.020.998	Rushmore
56	15.676.770	Nebraska
57	9.095.130	Sierra Southwest
58	7.316.861	Central Montana
59	1.355.325	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Total Operating Revenue

1	1,173,424,620	Seminole
2	1,128,879,000	Oglethorpe
3	911,164,597	North Carolina
4	880,892,682	Brazos
5	867,142,524	Associated
6	846,044,628	Tri-State
7	775,455,976	Central Electric - SC
8	710,031,000	Great River
9	650,959,941	East Kentucky
10	636,991,811	South Mississippi
11	628,716,081	Basin
12	617,660,934	Alabama
13	605,562,276	Arkansas
14	569,041,251	Wabash Valley
15	441,344,744	Hoosier
16	436,106,124	Golden Spread
17	402,149,402	Western Farmers
18	354,577,815	Buckeye
19	284,439,111	Dairyland
20	267,542,713	Chugach
21	230,236,571	Big Rivers
22	226,746,915	KAMO
23	222,652,052	Rayburn Country
24	218,755,725	Deseret
25	195,689,229	Wolverine
26	180,062,423	Allegheny
27	169,119,453	Sho-Me Power
28	167,056,500	PNGC Power
29	162,445,290	Northeast Texas
30	156,670,095	Saluda River
31	155,275,887	Minnkota
32	150,150,084	South Texas
33	140,835,920	Sunflower
34	140,111,115	Central Iowa
35	132,859,511	Nebraska
36	123,818,641	Southern Illinois
37	116,090,344	Central Electric - MO
38	110,774,319	Kansas Electric
39	104,447,074	San Miguel
40	94,558,537	Sam Rayburn
41	89,722,827	Square Butte
42	88,916,048	Tex-La
43	85,727,358	East River
44	84,950,951	Soyland
45	83,914,575	Corn Belt
46	63,292,761	Sierra Southwest
47	59,481,148	N. W. Electric
48	57,085,676	M & A Electric
49	47,919,538	Central Power - ND
50	45,042,736	Upper Missouri
51	44,069,475	Northeast Missouri
52	39,732,057	Northwest Iowa
53	36,282,325	Southwest Transmission
54	30,067,606	Rushmore
55	18,141,206	Power Resources
56	15,445,739	Central Montana
57	14,973,815	New Horizon
58	193,436	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Interest Income

1	46,313,000	Oglethorpe
2	33,533,549	Basin
3	23,655,254	Associated
4	17,624,561	East Kentucky
5	15,799,831	Big Rivers
6	13,373,292	Tri-State
7	10,226,937	Western Farmers
8	7,309,555	North Carolina
9	6,364,219	Great River
10	5,598,298	Allegheny
11	5,516,107	Seminole
12	4,603,281	Golden Spread
13	3,751,285	Deseret
14	3,749,197	Alabama
15	3,034,121	Brazos
16	2,792,856	Buckeye
17	2,634,379	Northeast Texas
18	2,539,413	Hoosier
19	2,495,207	Saluda River
20	2,236,570	Wolverine
21	2,067,646	Arkansas
22	2,066,052	Central Iowa
23	2,015,235	South Mississippi
24	1,347,525	Wabash Valley
25	1,313,072	San Miguel
26	1,312,136	Central Electric - MO
27	1,214,398	Central Electric - SC
28	1,171,833	Southern Illinois
29	1,131,563	Sunflower
30	1,063,918	East River
31	879,481	Chugach
32	875,646	Kansas Electric
33	833,608	Arizona
34	830,422	Soyland
35	829,373	PNGC Power
36	669,864	Dairyland
37	605,143	South Texas
38	552,327	Corn Belt
39	536,256	Tex-La
40	497,670	Southwest Transmission
41	490,005	Sho-Me Power
42	431,461	KAMO
43	423,755	M & A Electric
44	361,053	New Horizon
45	334,066	Northwest Iowa
46	310,585	Rayburn Country
47	215,053	Northeast Missouri
48	213,974	N. W. Electric
49	198,946	Minnkota
50	186,819	Central Power - ND
51	154,006	Sam Rayburn
52	146,940	Square Butte
53	85,641	Upper Missouri
54	84,713	Nebraska
55	83,493	Central Montana
56	71,568	Sierra Southwest
57	63,553	Power Resources
58	45,850	Rushmore
59	1,947	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Operating Margins

1	181,242,000	Oglethorpe
2	43,906,274	Buckeye
3	40,167,255	Great River
4	34,493,748	Brazos
5	19,840,147	Golden Spread
6	17,958,410	Big Rivers
7	15,227,215	Wolverine
8	13,581,970	Tri-State
9	13,149,388	Allegheny
10	9,509,429	Sho-Me Power
11	9,458,075	Dairyland
12	8,733,257	South Mississippi
13	8,676,483	Arkansas
14	8,562,510	Chugach
15	8,040,322	Alabama
16	7,863,804	Seminole
17	5,597,511	Central Iowa
18	5,529,207	Deseret
19	5,066,006	Hoosier
20	3,043,669	Sunflower
21	2,074,491	Sam Rayburn
22	2,032,168	San Miguel
23	1,931,296	South Texas
24	1,769,344	Power Resources
25	1,714,466	KAMO
26	1,636,529	East River
27	1,373,330	Wabash Valley
28	1,326,434	Tex-La
29	1,249,703	Central Electric - MO
30	1,041,657	Square Butte
31	973,458	Rayburn Country
32	957,482	M & A Electric
33	949,820	Northeast Missouri
34	600,946	Central Montana
35	280,558	Rushmore
36	174,958	Kansas Electric
37	130,086	Upper Missouri
38	67,999	Georgia
39	0	Northeast Texas
40	-14,131	Nebraska
41	-118,426	N. W. Electric
42	-131,540	Central Power - ND
43	-220,725	Southern Illinois
44	-284,805	Central Electric - SC
45	-303,793	PNGC Power
46	-315,018	New Horizon
47	-439,023	Western Farmers
48	-526,866	Minnkota
49	-865,549	Northwest Iowa
50	-1,700,313	Corn Belt
51	-6,972,076	East Kentucky
52	-10,455,219	North Carolina
53	-12,976,449	Associated
54	-24,394,266	Saluda River
55	-34,488,669	Basin

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Net Margins

1	55,962,773	Great River
2	45,928,154	Tri-State
3	43,656,430	Brazos
4	36,149,623	Buckeye
5	34,542,297	Big Rivers
6	26,286,249	Allegheny
7	25,171,157	Golden Spread
8	18,201,000	Oglethorpe
9	17,886,655	Wolverine
10	15,917,571	Arkansas
11	15,522,756	Associated
12	15,222,692	Sho-Me Power
13	14,281,618	Seminole
14	14,205,315	Alabama
15	11,438,938	Dairyland
16	11,173,989	East Kentucky
17	11,136,341	South Mississippi
18	10,829,905	Deseret
19	10,355,377	Western Farmers
20	10,104,457	Southern Illinois
21	10,039,059	Chugach
22	9,970,599	Central Iowa
23	8,535,671	Hoosier
24	6,365,873	North Carolina
25	6,240,482	Central Electric - MO
26	6,030,205	Sunflower
27	5,975,143	East River
28	5,387,080	KAMO
29	5,080,605	Basin
30	4,561,955	Central Montana
31	4,000,000	Wabash Valley
32	3,345,257	San Miguel
33	3,324,082	Tex-La
34	3,182,273	M & A Electric
35	3,101,698	Sam Rayburn
36	3,069,399	South Texas
37	2,640,508	Northeast Texas
38	2,498,263	Upper Missouri
39	2,404,266	Northeast Missouri
40	2,035,553	Central Power - ND
41	1,996,936	N. W. Electric
42	1,963,860	Power Resources
43	1,816,515	Rushmore
44	1,749,970	Square Butte
45	1,741,739	Northwest Iowa
46	1,543,764	Minnkota
47	1,532,963	Corn Belt
48	1,423,621	Rayburn Country
49	1,133,419	Central Electric - SC
50	1,046,681	Kansas Electric
51	640,607	Soyland
52	511,386	PNGC Power
53	234,277	New Horizon
54	70,941	Nebraska
55	11,085	Georgia
56	-19,887,426	Saluda River

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Tier

1	207.00	Brazos
2	7.27	Tex-La
3	5.41	Upper Missouri
4	4.70	Wolverine
5	3.80	Allegheny
6	3.55	Golden Spread
7	3.46	Sho-Me Power
8	3.13	Northeast Missouri
9	2.73	M & A Electric
10	2.67	Buckeye
11	2.55	Central Electric - MO
12	2.49	Northwest Iowa
13	2.32	East River
14	2.14	Central Power - ND
15	2.07	N. W. Electric
16	2.00	Rayburn Country
17	1.83	Great River
18	1.72	Power Resources
19	1.70	Sam Rayburn
20	1.68	Southern Illinois
21	1.61	Central Iowa
22	1.53	Arkansas
23	1.51	Dairyland
24	1.47	Big Rivers
25	1.41	Chugach
26	1.36	Minnkota
27	1.36	KAMO
28	1.35	San Miguel
29	1.33	Western Farmers
30	1.33	Deseret
31	1.33	Northeast Texas
32	1.32	Sunflower
33	1.32	Central Electric - SC
34	1.29	Alabama
35	1.26	Associated
36	1.25	South Mississippi
37	1.24	South Texas
38	1.24	Seminole
39	1.23	Wabash Valley
40	1.20	Hoosier
41	1.19	Soyland
42	1.16	Corn Belt
43	1.13	East Kentucky
44	1.12	Kansas Electric
45	1.11	Tri-State
46	1.11	North Carolina
47	1.09	Square Butte
48	1.05	New Horizon

2006 - Equity %

1	88.75	Rushmore
2	60.57	Northeast Missouri
3	54.17	M & A Electric
4	53.65	Upper Missouri
5	52.80	Central Electric - MO
6	47.53	Sho-Me Power
7	47.46	Wolverine
8	45.17	PNGC Power
9	43.14	N. W. Electric
10	40.61	Central Power - ND
11	37.67	Arkansas
12	37.15	Minnkota
13	37.05	Golden Spread
14	35.75	Buckeye
15	35.28	Northwest Iowa
16	34.33	East River
17	31.41	Northeast Texas
18	30.05	Chugach
19	27.01	Sam Rayburn
20	26.93	Basin
21	26.55	KAMO
22	20.42	Deseret
23	18.77	Rayburn Country
24	18.50	Soyland
25	18.19	South Texas
26	16.80	Central Iowa
27	16.39	Associated
28	15.12	Tri-State
29	14.31	New Horizon
30	13.93	Brazos
31	13.56	Corn Belt
32	13.14	Southern Illinois
33	12.74	Tex-La
34	12.46	Dairyland
35	12.30	Oglethorpe
36	12.23	Wabash Valley
37	11.95	Western Farmers
38	11.85	Great River
39	11.50	Allegheny
40	11.36	Hoosier
41	11.03	South Mississippi
42	10.89	San Miguel
43	9.89	Central Electric - SC
44	9.77	Georgia
45	9.46	Kansas Electric
46	9.28	Alabama
47	6.96	Seminole
48	6.29	Square Butte
49	5.28	East Kentucky
50	5.26	Nebraska
51	2.18	North Carolina
52	-17.33	Big Rivers
53	-19.06	Sunflower
54	-25.56	Power Resources

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Rate of Return on Rate Base

1	19.32	Nebraska
2	17.83	Power Resources
3	16.32	Buckeye
4	14.55	Wolverine
5	14.42	Golden Spread
6	12.50	Allegheny
7	11.53	Central Iowa
8	11.32	Georgia
9	10.87	Deseret
10	9.17	Big Rivers
11	8.89	Sunflower
12	8.61	Great River
13	8.01	Dairyland
14	7.73	Northeast Missouri
15	7.60	KAMO
16	7.51	East River
17	7.36	Wabash Valley
18	7.31	Rayburn Country
19	7.19	South Mississippi
20	7.00	Tri-State
21	6.98	Chugach
22	6.82	Alabama
23	6.80	M & A Electric
24	6.78	Hoosier
25	6.77	North Carolina
26	6.50	Square Butte
27	6.49	San Miguel
28	6.33	Western Farmers
29	5.85	Seminole
30	5.83	Arkansas
31	5.72	N. W. Electric
32	5.62	East Kentucky
33	5.53	South Texas
34	5.00	Corn Belt
35	4.29	Associated
36	3.85	Central Power - ND
37	2.79	Minnkota
38	2.59	Central Electric - MO
39	2.01	Basin
40	1.77	Northeast Texas
41	1.18	Northwest Iowa

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Amount of RUS Insured Debt

1	894,179,748	Big Rivers
2	95,260,266	South Texas
3	72,625,000	Tex-La
4	62,000,000	Sunflower
5	55,890,295	Central Electric - MO
6	49,506,837	East Kentucky
7	43,796,068	Alabama
8	37,641,676	Brazos
9	36,960,373	Western Farmers
10	32,858,465	Tri-State
11	31,971 310	Great River
12	27,390,926	KAMO
13	27,065,806	Central Electric - SC
14	25,341,064	Central Power - ND
15	21,535,966	Central Iowa
16	20,322,360	Sho-Me Power
17	18,235,020	East River
18	17,920,000	Hoosier
19	17,795,081	Northwest Iowa
20	15,816,504	M & A Electric
21	14,869,590	Dairyland
22	13,929,016	N. W. Electric
23	12,575,300	South Mississippi
24	10,445,000	Oglethorpe
25	9,943,463	Minnkota
26	6,818,811	Northeast Missouri
27	5,642,182	Basin
28	5,107,206	Seminole
29	5,064,479	Associated
30	4,888,374	North Carolina
31	3,774,538	Arkansas
32	3,419,995	Upper Missouri
33	2,297,342	Arizona
34	1,110,022	Southwest Transmission
35	1,031,000	Square Butte
36	679,650	Southern Illinois
37	519,460	Corn Belt
38	20,443	Power Resources
39	2,650	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

2006 Amount of FFB Debt

1	2,184,481,000	Oglethorpe
2	1,184,455,375	East Kentucky
3	1,118,554,321	Tri-State
4	1,036,132,241	Great River
5	915,979,184	North Carolina
6	707,401,840	Alabama
7	687,416,393	Brazos
8	644,219,942	South Mississippi
9	628,074,782	Seminole
10	609,601,441	Basin
11	486,839,540	Dairyland
12	435,383,520	Associated
13	342,150,391	Western Farmers
14	329,334,937	Arkansas
15	307,347,000	Hoosier
16	242,705,974	Southern Illinois
17	228,309,811	Buckeye
18	224,544,249	Central Iowa
19	168,544,054	KAMO
20	160,911,500	South Texas
21	154,720,679	Corn Belt
22	136,792,149	Arizona
23	128,137,153	Northeast Texas
24	93,026,076	San Miguel
25	79,232,070	Kansas Electric
26	73,024,030	Southwest Transmission
27	66,277,920	Tex-La
28	66,250,542	Sho-Me Power
29	43,831,678	Central Electric - SC
30	31,955,158	Sam Rayburn
31	26,225,050	East River
32	26,053,973	Minnkota
33	24,399,342	Power Resources
34	19,114,376	Central Electric - MO
35	9,843,662	M & A Electric
36	7,882,522	Northeast Missouri
37	5,799,353	Northwest Iowa
38	5,699,517	N. W. Electric
39	4,895,867	Central Power - ND
40	3,898,536	Upper Missouri
41	869,823	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

2006 - Amount of Total Debt

1	3,402,094,000	Oglethorpe
2	1,772,601,989	Tri-State
3	1,702,086,944	East Kentucky
4	1,469,885,554	Great River
5	1,376,865,167	Basin
6	1,218,135,347	Big Rivers
7	1,183,706,261	Seminole
8	1,030,129,726	Associated
9	1,025,798,874	North Carolina
10	985,388,366	Brazos
11	913,961,412	Alabama
12	808,584,000	Hoosier
13	722,964,790	South Mississippi
14	620,706,240	Western Farmers
15	586,499,324	Dairyland
16	537,788,745	Arkansas
17	373,603,060	Buckeye
18	364,532,099	Chugach
19	357,333,049	Sunflower
20	332,512,352	Saluda River
21	330,625,388	Wabash Valley
22	318,334,595	Deseret
23	303,742,814	Square Butte
24	298,516,814	Central Iowa
25	280,327,488	Southern Illinois
26	256,171,766	South Texas
27	232,274,256	KAMO
28	195,415,425	Arizona
29	189,721,400	Allegheny
30	176,887,184	Corn Belt
31	170,226,076	San Miguel
32	153,434,985	Kansas Electric
33	152,796,433	Golden Spread
34	138,902,920	Tex-La
35	138,897,944	Northeast Texas
36	111,344,105	Sho-Me Power
37	95,492,277	Southwest Transmission
38	95,254,151	Minnkota
39	94,755,136	East River
40	90,570,413	Wolverine
41	83,093,278	Central Electric - SC
42	75,004,671	Central Electric - MO
43	71,196,450	New Horizon
44	48,323,194	Soyland
45	36,417,637	Sam Rayburn
46	35,978,236	Power Resources
47	33,787,510	N. W. Electric
48	33,476,528	M & A Electric
49	32,421,861	Central Power - ND
50	23,594,434	Northwest Iowa
51	20,837,729	Rayburn Country
52	18,531,987	Northeast Missouri
53	8,876,421	Upper Missouri
54	1,156,630	Georgia

Note: Member Information Excluded if No Data Available or Category N/A

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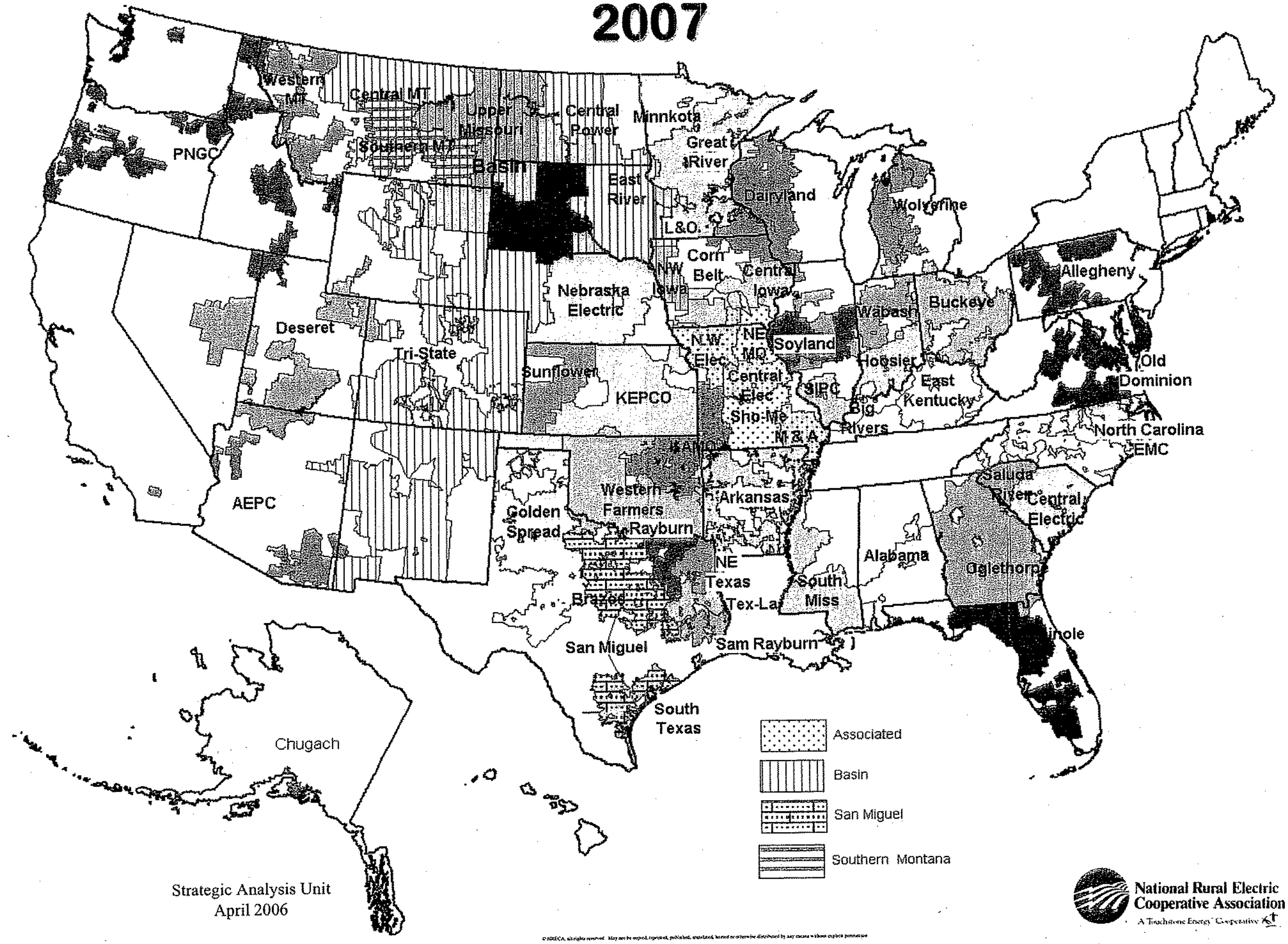
G&T Cooperative Service Areas 2007



Strategic Analysis Unit
April 2006

National Rural Electric Cooperative Association
A Touchstone Energy Cooperative

Item 57) Please reference the testimony of Mark W. Glotfelty, page 7. Provide the entire document from which the table on this page was drawn.

Response) Please reference the June 2007 G&T Accounting & Financial Association annual directory, AG Item 56.

Witness) Mark W. Glotfelty

Item 58) Please reference the testimony of Mark W. Glotfelty, page 10, line 19, regarding the "peer group."

a. Describe and discuss how these entities were determined to be "peers"; and

b. Identify any other companies that were considered for inclusion, but were rejected, and state why such companies were rejected.

Response) The peer group was selected based on their public ratings which primarily fall into the single A and BBB rating categories. Companies that were not included were Associated Electric, Brazos Electric, Buckeye Power, Central Iowa, Dairyland Power, Golden Spread, Oglethorpe Power, San Miguel, Seminole Electric and South Texas Electric.

Witness) Mark W. Glotfelty

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 59) Please reference the testimony of Mark W. Glotfelty, page 6, regarding "20 rated investment grade G&T's."

a. Describe and discuss how these 20 G&T's were identified and selected;

b. Provide the universe of G&T's that were initially considered (from which the 20 were drawn) along with information comparable to that in the table on page 7;

c. Provide documents showing all G&T's in the U.S. to the extent different than the above.

Response) The 20 G&T that were selected as the peer group represent substantially the entire rated universe of G&Ts. The information on the peer group can be found in the June 2007 G&T Accounting & Finance Association annual directory, AG Item 56.

Witness) Mark W. Glotfelty