

2002 ANNUAL REPORT

SOUTHWEST POWER POOL

TODAY AND IN THE FUTURE



Members

>> investor-owned

American Electric Power #
 Public Service Company of Oklahoma
 Southwestern Electric Power Company
 Aquila, Inc.
 Missouri Public Service #
 St. Joseph Light & Power *
 WestPlains Energy #
 Cleco Corporation #
 Entergy Services, Inc. *
 Exelon Power Team *
 Kansas City Power & Light Company #
 OG+E Electric Services #
 Southwestern Public Service Company #
 The Empire District Electric Company #
 Westar Energy #
 Western Resources, Inc.
 Kansas Gas & Electric

>> cooperatives

Arkansas Electric Cooperative Corporation *
 East Texas Electric Cooperative, Inc. *
 Kansas Electric Power Cooperative
 Midwest Energy, Inc. *
 Northeast Texas Electric Power Corporation *
 Sunflower Electric Power Corporation # *
 Tex-La Cooperative of Texas, Inc. *
 Western Farmers Electric Cooperative #

>> municipals

City of Clarksdale, Mississippi *
 City of Lafayette, Louisiana # *
 City Power & Light, Independence, Missouri # *
 City Utilities, Springfield, Missouri *
 Public Service Community of Yazoo City, Mississippi *
 The Board of Public Utilities, Kansas City, Kansas # *

>> state agencies

Grand River Dam Authority #
 Louisiana Energy & Power Authority #
 Oklahoma Municipal Power Authority

>> federal agency

Southwestern Power Administration #

>> independent power producer

Tenaska Power Services Company *

>> marketers

Aquila Power - Aquila, Inc. *
 Calpine Energy Services, L.P. *
 Cargill - Alliant, LLC *
 Cinergy Corporation *
 Constellation Power Source *
 Coral Power LLC *
 Duke Energy Trading & Marketing *
 Dynegy Marketing & Trade *
 Edison Mission Marketing & Trading, Inc. *
 El Paso Merchant Energy, L.P. *
 LG&E Energy Marketing *
 Mirant Americas Energy Marketing, L.P. *
 NRG Power Marketing, Inc. *
 PG&E National Energy Group *
 Reliant Energy Services, Inc. *
 TXU Energy Trading Company
 Williams Energy Marketing & Trading Company *

Member Statistics as of 10/31/2002

14	Investor-Owned	8	Cooperatives
6	Municipals	3	State Agencies
1	Federal Agency	1	Independent Power Producer
17	Marketers		

50 Members

* Transmission Dependent Member # Denotes Control Areas within SPP



Helping our **members** work to keep the lights
on **today** and in the **future**.

A **member-driven, relationship-based,**
evolutionary organization.

FROM OUR CHAIRMAN

2002 was a pivotal year for Southwest Power Pool. This 60-plus-year-old organization was expected, at least in name, to be no more.

In July 2001, we learned that SPP would not receive recognition as a Regional Transmission Organization (RTO) from the Federal Energy Regulatory Commission (FERC). This action, as well as other regulatory issues, prompted SPP to consider other options.

We began merger discussions in August 2001 with the Midwest Independent Transmission System Operator (MISO) for purposes of creating an RTO for the mid-section of the country. The benefits to such a merger were significant: seams issues would be eliminated; greater access to generation across a larger footprint; and, economies of scale of a larger region. An agreement to consolidate the organizations was executed in early March of 2002.

As the year progressed, we experienced considerable changes in the industry, particularly in the regulatory arena, both at the state and federal level. The FERC Notice of Proposed Rule-making for the Standard Market Design created significant debate as to the purpose for markets, and the role of the federal and state regulators in the design and development of them. This debate continues although significant progress has been made to bring expectations closer together.

Many of the drivers of the merger took a turn as we moved through the year. The regulatory environment experienced change in regard to markets and regional organizations. SPP members and state regulatory agencies began to reconsider the benefits of and necessity for consolidating the organizations. In early 2003, SPP and MISO mutually agreed to terminate the merger effort.

Southwest Power Pool has learned a great deal from the events of 2002. While not the year we planned, it has been very beneficial to the organization. SPP's members and staff are focused and committed to this historic organization. Our foundation for moving forward is strong. On behalf of the Board of Directors and myself we look forward to assisting the members in pursuing the many opportunities available to SPP.



Al M. Strecker

Al M. Strecker

Executive Vice President, Chief Operating Officer
OGE Energy Corporation, OG&E Electric Services

FROM OUR PRESIDENT

It has been five years since Southwest Power Pool, Inc. last issued an annual report. Our resources were redirected to our website with the intent of providing the same information in a more real-time up-to-date fashion. While this occurred, one thing has been missing—an annual record of our history. The company has experienced considerable change during the past five years. Here is a glimpse of our evolution:

- We implemented independent regional security coordination in 1997 to better protect system reliability
- We implemented independent regional tariff administration in 1998 to more efficiently, effectively, and reliably utilize the transmission assets of our members (beginning with only non-firm and short-term firm point-to-point service, adding long-term firm point-to-point in 1999, and adding network service in 2001)
- We implemented regional transaction scheduling in 2001 to more efficiently schedule power
- Membership has both declined and grown to now include 50 entities representing all facets of the industry
- Our staff has grown to over 100
- Participation in committees, working groups, and task forces has increased significantly



John Marschewski

This evolutionary change all took place while experiencing considerable change in the industry—deregulation of the wholesale electricity market, issuance of FERC Order 2000, and financial uncertainty of many utilities.

While creating extensive change – and uncertainty – these events have provided important learning opportunities for SPP as we have moved through them. SPP is poised and ready for more changes ahead, but as we have learned, some things just simply need to remain the same:

- We must always maintain our member-driven focus as it is our members working together that create our successes
- We must maintain our close relationships developed over our 60-year history as this glue is stronger than any contract
- We must maintain our independence through diversity as “skin in the game” provides the best oversight
- We must never try to separate reliability and economic/equity issues as it is simply not possible, and
- We must continue to evolve in a rational manner in the best interest of our stakeholders, avoiding radical changes

The lessons learned will serve the organization well and the staff at Southwest Power Pool will continue “Helping our Members work together to keep the lights on . . . today and in the future!”

John Marschewski
President

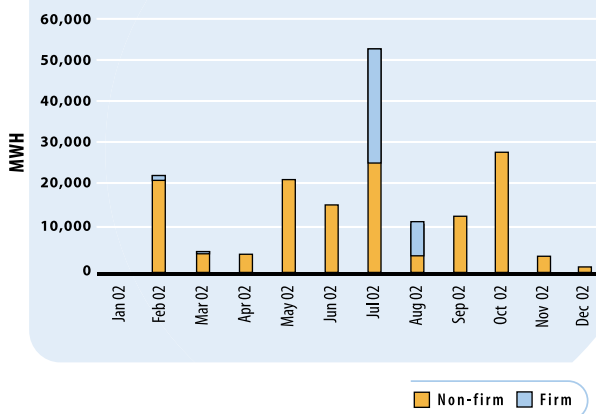
Regional Operations

Security Coordination

SPP is a NERC-recognized reliability coordinator providing regional reliability coordination services to its members out of its coordination center in Little Rock. This center operates around-the-clock and is staffed with NERC-certified operating personnel averaging 26 years of industry experience. As a reliability coordinator, SPP is responsible for reliability of the electric transmission system of its members and has the authority to direct actions required to maintain adequate regional generation capacity, adequate system voltage levels, and transmission system loading within specified limits. SPP also coordinates planned transmission and generation outages with its members and neighbors.

The primary method utilized by SPP to relieve excessive loading on transmission facilities is NERC's Transmission Loading Relief (TLR) procedure. This procedure calls for reduction of energy schedules impacting an identified over-loaded facility or facilities. SPP experienced significant TLR activity in 2002. For the year, SPP had 151 events, 17 of which involved curtailment of firm transmission service. Twenty-one events, seven of which involved curtailment of firm transmission service, were directly attributable to significant transmission outages in the northern Oklahoma area that occurred as a result of the January 30 ice storm. Approximately 177,000 MWH of energy flows were curtailed for 2002 due to TLR with 53,000 MWH being curtailed in the peak month of July. The most significant curtailments occurred on the LaCygne-Stilwell 345 kV line due to heavy south-to-north energy flows resulting from unusually hot temperatures in the Mid-Continent Area Power Pool (MAPP) and Mid-America Interconnected Network, Inc. (MAIN) regions, and this facility's susceptibility to being impacted by parallel flows.

Monthly MWH Curtailed due to TLR

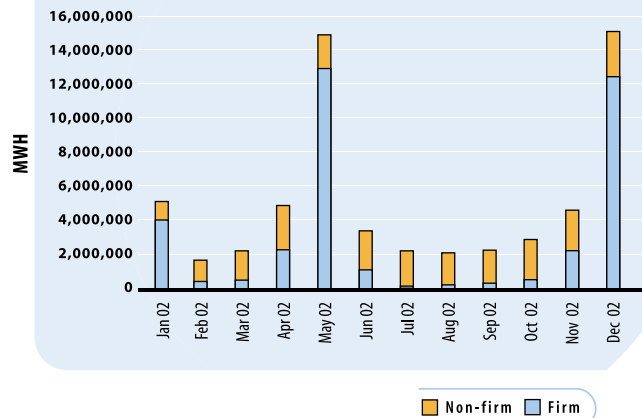


Tariff Administration

SPP administers an Open Access Transmission Tariff (OATT) providing regional transmission service across ten transmission owners in all or part of seven southwestern states. A staff of experienced tariff administrator, engineering, accounting, and regulatory personnel located in Little Rock performs services for SPP members and customers. These services include calculating and posting ATC, processing requests for service, performing impact and facility studies, providing tariff billing and revenue distribution, and providing regulatory assistance.

The majority of SPP transmission service sold was approved in the months of May and December. SPP approved 14.9 and 15.2 million MWH in those months, respectively. Transmission constraints, observed most heavily in summer months, severely reduced SPP's ability to sell firm transmission service during the summer months.

Transmission Service Approved



Despite a severely constrained transmission system in the SPP region, SPP was able to provide a substantial amount of transmission service in 2002. Active transmission service peaked in December at nearly 12.2 million MWH. Transmission service revenue received in 2002 totaled \$160,000,000.

The SPP OATT includes procedures for interconnecting new generation to the transmission system. As of December 31, 2002, there were a total of 47 requests for generation addition representing a total of 16,046 MW. SPP received 26 requests for additional generation in 2002 under the OATT. All of the new requests were from independent

power producers and represented a total of 7,150 MW of generation proposed to be added to the SPP system. Approximately half of all the requests completed the engineering study phase and are in active negotiation for Interconnection Agreements, while the balance are in various stages of study. Twenty-three of the requests represented wind farm developments; three represented fossil fueled generators. The Texas panhandle, western Oklahoma, and the Kansas prairie are prime locations for wind farm development. This combined with the current tax incentives has increased wind farm developments, some numbering in the thousands of megawatts, increasing the amount of wind generation requested on the SPP system to over 6,700 MW.

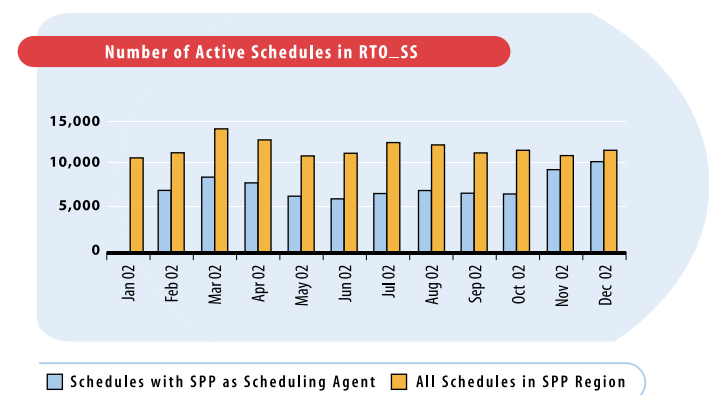
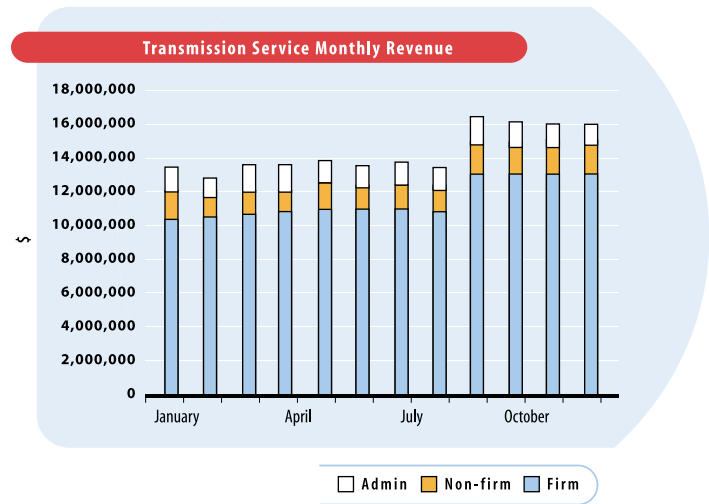
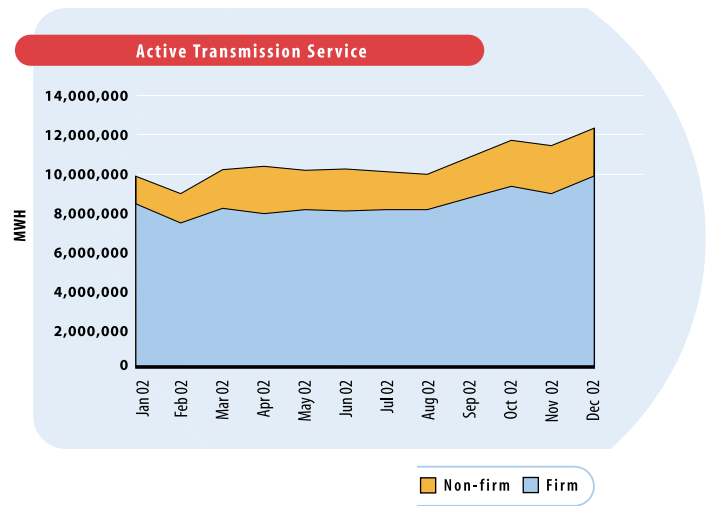
Scheduling

SPP began a phased implementation of its regional scheduling function by making its electronic scheduling system (RTO_SS) available to its members in May 2001. Many SPP control areas then relied solely on RTO_SS to indicate official schedule status beginning October 15, 2001.

SPP began the next phase of its regional scheduling function on February 1, 2002. This phase required SPP to act as a scheduling entity for all interchange transactions using SPP regional transmission service. The final phase was implemented on November 1, 2002, when SPP commenced serving as a scheduling entity for all transactions using grandfathered transmission service of the SPP transmission owners under the regional tariff, excluding Southwestern Power Administration (SPA).

The number of active schedules in the SPP region peaked at nearly 14,000 schedules in March 2002, with SPP acting as a scheduling entity on approximately 8,400 of those. The number of active schedules in the region began to decrease with the implementation of E-tag version 1.7 in April 2002. SPP's activity as scheduling entity peaked in December 2002, when it was involved in more than 10,000 active schedules in the region.

The addition of scheduling entity services to the regional scheduling function has provided significant timesaving benefits to the SPP members. SPP's regional scheduling function greatly reduces the number of scheduling entities with which an SPP control area must coordinate and improves the management of interchange transactions and schedules. SPP is now truly the single point of contact for scheduling and reserving SPP regional transmission service.



Regional Planning

Transmission Assessment

During 2002, SPP experienced a higher than normal level of TLR activity due to regional coordination issues surrounding the LaCygne – Stilwell 345 kV flowgate in the Kansas City area. The LaCygne – Stilwell 345 kV line is a critical outlet for large base-load generating units owned by Westar Energy and Kansas City Power & Light Company (KCPL). The LaCygne – Stilwell transmission line is also heavily impacted by merchant activity in the SPP region, as well as in the Southeastern Electric Reliability Council (SERC) and MAPP regions. The transmission line has been a constraint in the region in recent history. This circuit's capacity will be upgraded from 1,251 MVA to 1,972 MVA. KCPL will be responsible for constructing the upgrade with a target completion date of July 1, 2003. This reconductoring should relieve constraints on the facility for 2003.

Seasonal studies were performed on the current and planned bulk transmission system that represents more likely operational states. These studies determine First Contingency Incremental Transfer Capability (FCITC) and give a relative indication of the network's ability to move power between various areas of the electrical network. The FCITC measure indicates incremental capability under first contingency (i.e. – additional transfer above that already scheduled between systems), and is indicative of the relative strength of the transmission system. Transmission studies show marginal improvements in regional and sub-regional transfer capabilities from season to season, and these capabilities remain adequate to handle planned transactions, with the exception of SPP regional and sub-regional imports from SERC and Entergy, respectively, which are inadequate.

Based on the most recent analysis of the SPP, MAIN, MAPP, and SERC interfaces, completed by the MAIN Transmission Assessment Study Group, all SPP regional import interfaces are found to be limited by the Fort Smith 500/161 kV transformer (OKGE) for the outage of Fort Smith 345/161 kV transformer (OKGE). While this limitation was consistent for all the interfaces studied, all transfer levels are judged to be adequate.



Demand and Energy Assessment

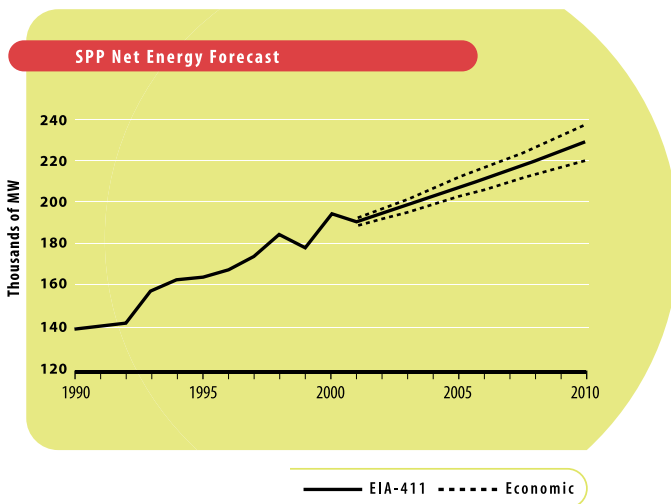
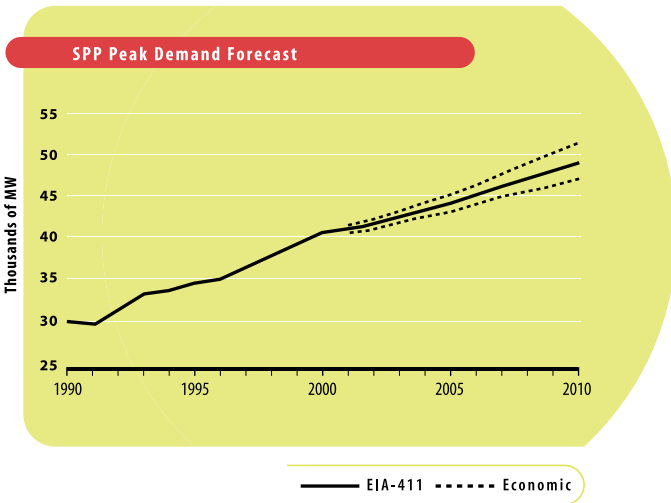
Data reported by SPP members in EIA-411 reports over the last ten years, provides actual and forecast peak demand and energy for the region. The forecast is a summation of all SPP member forecasts and represents the most probable demand and energy requirement for electricity over the next decade.

The 2002 SPP non-coincident peak for SPP members was 39,688 MW. This was 1.5% below the 2002 actual summer peak demand of 40,273 MW and 4.5% below the forecast 2002 summer peak demand of 41,483 MW. The 2003 non-coincident summer peak demand is forecast to be 40,564 MW, 2.2% above the actual summer peak demand. The region's 2002 actual net energy for load of 194,876 GWh was 0.7% above the 2001 actual of 193,590 GWh.

The SPP Bandwidth Working Group developed high and low growth rate scenario bands around the current demand and energy forecast for the SPP region as reported to the U.S. Department of Energy in the April 2001 EIA-411 report. These were produced through econometric modeling of the two newly formed sub-regions. Aggregating the sub-regional results produced the SPP regional values. The following tables summarize growth rates that bound the most likely range of occurrence of peak demand forecast and net energy forecast, respectively, under normal weather conditions.

Generation Assessment

According to data in the April 1, 2002, EIA-411 report, the SPP capacity margin for 2002 was projected to be 18.33%, well above the minimum criteria for individual members of 12%. With this capacity margin, the SPP system did not experience capacity shortfall during 2002. The projected capacity margin for 2003 is 18.57%, again well above the minimum criteria for individual members of 12%. SPP expects to be above the minimum required capacity margin throughout the ten-year planning horizon due to the addition of several thousand megawatts of merchant generation in the region. The capacity margin does not reflect the entire amount of new capacity added to the region. Uncommitted merchant generation capacity exists in the region that is not included in the EIA-411, which would provide additional generation resources should unit contingencies occur.



SPP is projected to be **above** the minimum required **capacity** margin throughout the **10-year planning horizon**.

INDEPENDENT AUDITOR'S REPORT

To the Board of Directors and Members of
Southwest Power Pool
Little Rock, Arkansas

We have audited the accompanying balance sheets of Southwest Power Pool (the "Company") as of December 31, 2002 and 2001, and the related statements of income and members' equity and of cash flows for the years then ended. 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. 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, such financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2002 and 2001, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

DeBitt & Touche LLP

March 10, 2003, except for Note 8,
which is March 20, 2003
Little Rock, Arkansas

Balance Sheet

December 31, 2002 and 2001

	2002	2001
Assets		
Current Assets:		
Cash and cash equivalents	\$ 7,266,977	\$ 9,168,431
Accounts receivable:		
Trade	1,787,733	767,929
Tariff	16,373,179	7,655,593
Other	<u>10,761</u>	<u>10,761</u>
Total accounts receivable	18,160,912	8,434,283
Prepaid expenses	<u>251,649</u>	<u>40,191</u>
Total current assets	25,679,538	17,642,905
Property and Equipment, Net	23,289,498	26,150,326
Other, Net	<u>322,128</u>	<u>424,872</u>
Total	<u>\$ 49,291,164</u>	<u>\$ 44,218,103</u>
Liabilities and Members' Equity		
Current Liabilities:		
Accounts payable:		
Trade	\$ 615,294	\$ 130,571
Tariff	<u>15,211,422</u>	<u>7,049,534</u>
Total accounts payable	15,826,716	7,180,105
Customer deposits	4,939,297	6,542,557
Accrued expenses	1,429,421	1,200,257
Long-term debt - current portion	<u>2,000,000</u>	<u> </u>
Total current liabilities	24,195,434	14,922,919
Long-term Debt	<u>25,000,000</u>	<u>25,000,000</u>
Total liabilities	49,195,434	39,922,919
Commitments and Contingencies		
Members' Equity	<u>95,730</u>	<u>4,295,184</u>
Total	<u>\$ 49,291,164</u>	<u>\$ 44,218,103</u>

See notes to financial statements.

Statements of Income & Members' Equity

For the years ended December 31, 2002 and 2001

	2002	2001
Income:		
Member assessments	\$ 10,553,865	\$ 9,607,512
Tariff fees	16,268,153	8,425,263
Other member services	2,014,901	1,981,197
Interest income	143,469	1,100,552
Other	<u>349,039</u>	<u>475,678</u>
Total income	29,329,427	21,590,202
Expenses:		
Salary and benefits	10,983,822	10,085,042
Employee travel	759,573	633,209
Administrative	777,332	564,580
NERC assessment	810,130	868,398
SPP/NERC meetings	108,400	250,417
Communications system	1,034,463	644,539
Leases and maintenance	1,449,528	761,703
Office supplies	408,935	840,536
Consulting services	10,241,557	2,769,976
Depreciation and amortization	4,376,684	1,699,393
Interest expense	2,244,623	1,294,746
Miscellaneous	<u>337,680</u>	<u>58,623</u>
Total expenses	<u>33,532,727</u>	<u>20,471,162</u>
Net Income (Loss)	(4,203,300)	1,119,040
Members' Equity:		
Beginning of year	4,295,184	3,176,144
Members' contributions	<u>3,846</u>	<u> </u>
End of year	<u>\$ 95,730</u>	<u>\$ 4,295,184</u>

See notes to financial statements.

Statement of Cash Flows

For the years ended December 31, 2002 and 2001

	2002	2001
Operating Activities:		
Net income (loss)	\$ (4,203,300)	\$ 1,119,040
Adjustments to reconcile net income (loss) to		
Cash used in operating activities:		
Depreciation and amortization	4,376,684	1,699,393
(Gain) loss on disposal of property & equipment	(21,833)	11,205
Changes in assets and liabilities:		
Accounts receivable	(9,726,629)	(64,976)
Prepaid expenses	(211,458)	(78,386)
Accounts payable	8,646,611	(1,042,902)
Customer deposits	(1,603,260)	(6,976,742)
Accrued liabilities	229,164	749,021
Net cash used in operating activities	<u>(2,514,021)</u>	<u>(4,584,347)</u>
Investing Activities:		
Purchase of property and equipment	\$ (1,414,279)	\$ (23,043,287)
Proceeds on disposal of property and equipment	<u>23,000</u>	<u> </u>
Net cash used by investing activities	(1,391,279)	(23,043,287)
Financing Activities:		
Loan acquisition costs		(201,963)
Contributions from members	3,846	
Proceeds from long-term debt	2,000,000	25,000,000
Repayment of obligations under capital leases		(567,941)
Repayments of long-term debt		<u>(5,252,541)</u>
Net cash provided by financing activities	<u>2,003,846</u>	<u>18,977,555</u>
Net Decrease in Cash and Cash Equivalents	(1,901,454)	(8,650,079)
Cash and Cash Equivalents:		
Beginning of year	<u>9,168,431</u>	<u>17,818,510</u>
End of year	<u>\$ 7,266,977</u>	<u>\$ 9,168,431</u>
Supplemental Disclosure of Cash Flow Information		
Cash paid during the year for interest	<u>\$ 2,244,623</u>	<u>\$ 2,756,366</u>

See notes to financial statements.

Financial Notes

For the years ended December 31, 2002 and 2001

1. Organization and Significant Accounting Policies

Nature of Operations - Southwest Power Pool (the "Company") was incorporated January 1, 1994, to facilitate joint planning and coordinating the generation and transmission systems of the members of the Company and to participate in interregional studies to provide for increased operating efficiency, adequate bulk supply systems, and better service reliability. In 1998, the Company commenced its open access transmission operations, whereby the Company provides "one-stop-shopping" for short-term firm and non-firm point-to-point transmission services, firm point-to-point transmission services, and network transmission service across 11 providers in seven southwestern states. The Company had 50 members as of December 31, 2002, operating in Kansas, Arkansas, Missouri, Mississippi, Louisiana, Texas, Oklahoma, and New Mexico.

During March 2002, the Board of Directors of the Company approved the sale of the Company's assets to Midwest Independent Transmission System Operator, Inc. ("MISO"). The Company and MISO received final approval from the Federal Energy Regulatory Commission ("FERC") during May 2002 (see Note 8).

Basis of Accounting - The Company prepares its financial statements on the accrual basis of accounting. Revenues, consisting of member assessments, tariffs, working capital contributions from members, and miscellaneous revenues are recognized when earned, and expenses are recognized when incurred.

Cash and Cash Equivalents - The Company considers all short-term investments with maturities at acquisition of three months or less to be cash equivalents.

Property and Equipment - Property and equipment are stated at cost. Depreciation is calculated by the straight-line method over the estimated useful lives of the assets.

Internal Use Software Costs - The Company capitalizes certain internal use software costs in accordance with Statement of Position 98-1, *Accounting for the Costs of Computer Software Developed or Obtained for Internal Use*. These costs are included in property and equipment.

Customer Deposits - Customers are required to make deposits with the Company prior to the performance of transmission services. These amounts are typically held for the duration of the service and applied to the customer's final invoice.

Use of Estimates - The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Income Taxes - The Company is classified as a Section 501(c)(6) business league and is exempt from federal income tax.

Impairment of Long-Lived Assets and Long-Lived Assets to be

Disposed of - Effective January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets* ("SFAS 144"). Under SFAS 144, long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceed the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. The adoption of SFAS 144 did not have a material effect on the Company's financial position or results of operations.

Recently Issued Accounting Standards - In June 2002, the Financial Accounting Standards Board ("FASB") issued SFAS No. 146, *Accounting for Costs Associated with Exit or Disposal Activities*. This Statement requires that a liability for costs associated with an exit or disposal activity be recognized when the liability is incurred and be measured at fair value and adjusted for changes in estimated cash flows. Existing generally accepted accounting principles provide for the recognition of such costs at the date of management's commitment to an exit plan. Under SFAS No. 146, management's commitment to an exit plan would not be sufficient, by itself, to recognize a liability. The Statement is effective for exit or disposal activities initiated after December 31, 2002. The adoption of SFAS 146 is not expected to have a material effect on the Company's financial position or results of operations.

In November 2002, the Financial Accounting Standards Board ("FASB") issued FASB Interpretation 45, *Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* ("FIN 45"). For financial statements issued after December 15, 2002, FIN 45 requires that a guarantor make certain disclosures regarding guarantees or indemnification agreements. Starting January 1, 2003, FIN 45 will require that a liability be recognized at the fair value of the guarantee. The adoption of FIN 45 is not expected to have a material effect on the Company's financial position or results of operations.

2. Property and Equipment

The Company's property and equipment consisted of the following at December 31:

Property and Equipment		
	2002	2001
Furniture and fixtures	\$ 2,113,962	\$ 1,491,274
Equipment and machinery	4,010,002	3,912,508
Software	10,485,121	7,798,379
Software in development	<u>16,650,332</u>	<u>19,050,332</u>
	33,259,417	32,252,493
Less: accumulated depreciation and amortization	<u>(9,969,919)</u>	<u>(6,102,167)</u>
Property and equipment, net	<u>\$ 23,289,498</u>	<u>\$ 26,150,326</u>

Depreciation was approximately \$4,336,000 and \$1,659,000, respectively, in 2002 and 2001.

During 2001, the Company accepted delivery of software in development to support the emerging wholesale energy market under FERC Order No. 2000 (the "Order"). The software system is composed of three major components: customer service, power operations, and settlement/invoicing. The design of the system is to enable the Company to operate a real-time balancing market, which facilitates the purchase and sale of energy in real-time, and meet the requirements, under the Order of being the provider of last resort for ancillary services. Although the power operations, and related settlement/invoicing, have been idle during the merger discussions (see Note 8), the customer service component has been utilized for call tracking by the customer service department. The power operations and settlement/invoicing components will be used as the core for development of the Independent Systems Operator ("ISO") system and will be used in any future market activities by the Company. Management of the Company is of the opinion that all costs capitalized in association with the software in development are fully recoverable over the anticipated life of the asset.

3. Commitments and Contingencies

At December 31, 2002, the Company was obligated under various noncancelable operating lease agreements for office space and communication connections. For the years ended December 31, 2002 and 2001, the Company incurred lease expense for lease payments under these operating leases of \$1,449,528 and \$761,703, respectively. Future minimum lease payments under these leases are as follows:

Commitments and Contingencies

2003	\$ 959,140
2004	641,414
2005	659,206
2006	677,531
2007	668,627
Thereafter	<u>2,792,573</u>
Total	<u>\$ 6,398,491</u>

The Company entered into an agreement for the development of software to be used for internal use. Total costs capitalized as of December 31, 2002, for this project is \$20,332,000, which is included as software in property and equipment. Remaining commitments under this agreement are approximately \$1,500,000 per year, with inflationary increases, through 2006 for commercial operations outsourcing services.

4. Long-Term Debt

In 2001, the Company authorized and issued \$25,000,000 aggregate principal amount of its 7.5% senior notes due March 15, 2008. Principal is payable \$5,000,000 per year, beginning in 2004 through 2008. The debt was used to construct market settlement software and is unsecured.

At December 31, 2002 and 2001, the Company had a \$4,000,000 line-of-credit agreement with a bank, which expires in June 2003. Interest on these borrowings is computed at a variable rate based on the bank prime rate (4.25% at December 31, 2002). At December 31, 2002, \$2,000,000 was outstanding under this arrangement.

5. Related Party Transactions

General disbursements of the Company are apportioned to members based on the formula described in the Bylaws of the Company. During the years ended December 31, 2002 and 2001, disbursements for the SPPNET project, AEP Project, ARS Project, and Frame Relay Project were billed directly to those members participating in such projects. The Company's receivables from members totaled \$1,793,070 and \$767,929 at December 31, 2002 and 2001, respectively. The Company recognized revenues of \$10,553,865 and \$9,607,512 from members for the years ended December 31, 2002 and 2001, respectively.

Those members who choose to terminate their membership in the Company are assessed an amount for their portion of the long-term financial obligations that the Company incurred while they were a member. The Company has a receivable from departed members in the amount of \$183,859 as of December 31, 2002.

6. Employee Benefit Plans

a. Employee Retirement Plan

The Company has a defined benefit pension plan (the "Plan") which covers substantially all employees. Benefits are based on final average monthly earnings and benefit service to retirement date.

The funded status of the Plan as of December 31, is as follows:

Defined Benefit Pension Plan

	2002	2001
Projected benefit obligation	\$ 5,186,542	\$ 4,099,580
Plan assets at fair value, primarily mutual funds	<u>2,206,766</u>	<u>1,808,510</u>
Projected benefit obligation in excess of plan assets	<u>\$ (2,979,776)</u>	<u>\$ (2,291,070)</u>

The prepaid pension asset was \$200,968 and \$263,325 at December 31, 2002 and 2001, respectively. Net periodic pension cost for 2002 and 2001 was \$699,379 and \$461,804, respectively. Contributions to the plan were \$637,020 and \$499,999 for 2002 and 2001, respectively. No benefits were paid during 2002 and 2001. The weighted average discount rate used in determining the actuarial present value of the projected benefit obligation and the expected long-term rate of return on assets was 7% for 2002 and 2001. The assumed rate of increase in future compensation levels used was 4% for 2002 and 2001.

Financial Notes (CONTINUED)

b. Defined Contribution Plan

The Company has a defined contribution plan (the "401(k) plan") which covers all employees who choose to participate. The Company's policy is to contribute a percentage of the amount the employee elects to contribute. The Company's contributions to this plan totaled \$314,681 and \$296,291 in 2002 and 2001, respectively.

c. Postretirement Benefits Other Than Pensions

The Company has a postretirement health plan for eligible retirees. The Company provides its retirees, including those retiring between the ages of 55-65 and hired prior to January 1, 1996, the same health care benefits and premium payments provided to active employees.

The funded status of the plan is as follows:

Postretirement Health Plans		
	2002	2001
Accumulated postretirement benefit obligation:		
Eligible active employees	\$ 179,807	\$ 147,894
Other active employees	<u>1,668,037</u>	<u>1,368,273</u>
Total accumulated postretirement benefit obligation	1,847,844	1,516,167
Plan assets at fair value, primarily mutual funds	<u>980,275</u>	<u>617,606</u>
Excess of accumulated postretirement benefit obligation over plan assets	\$ (867,569)	\$ (898,561)

The accrued postretirement health benefit liability was \$8,308 at December 31, 2002 and 2001. Net periodic postretirement benefit cost was \$319,437 and \$237,986 for 2002 and 2001, respectively. Contributions to the plan totaled \$319,437 and \$237,986 for 2002 and 2001, respectively. No benefits were paid during 2002 and 2001.

The health care cost trend rate used to measure the expected cost of benefits was 8% in 2002 and is assumed to decline by one percentage point each year to a minimum of 5% assumption in five years.

The weighted average discount rate used in determining the actuarial present value of projected benefit obligations and the expected long-term rate of return on assets was 7% in 2002 and 2001.

7. Open Access Transmission Operations

The Company provides "one-stop-shopping" for short-term firm and non-firm point-to-point transmission services, firm point-to-point transmission service and network service across 11 providers in 7 southwestern states. The Company receives fees from transmission customers for the use of the transmission lines. The Company keeps a portion of the amount received from the customer as a fee for facilitating the transmission process. This portion is recorded as tariff fees in the Company's statement of income. For the years ended December 31, 2002 and 2001, the Company generated gross fees of \$176,394,211 and

\$97,088,684, respectively, from customers of the open access transmission operations and incurred gross expenses of \$160,126,058 and \$88,663,421, respectively, to the transmission providers for use of their lines. At December 31, 2002 and 2001, the Company had recorded in the balance sheet, receivables from transmission customers of \$16,373,179 and \$7,655,593, respectively. The Company had payables to transmission providers of \$15,211,422 and \$7,049,534, respectively, at December 31, 2002 and 2001.

8. Subsequent Events

On March 20, 2003, the Company and MISO mutually agreed to terminate the consolidation of the organizations. Maintaining its separate, independent status, the Company will continue to coordinate the generation and transmission systems for the members of the Company. FERC has been informed of the termination of the proposed sale of the Company's assets to MISO.

Also on March 20, 2003, the Company's Board of Directors (the "Board") formed the Strategic Planning Task Force to completely review the Company's organization considering the current industry environment and to make appropriate recommendations to the Board. The Company's Board and management plan to implement the power operations and settlement/invoicing components (see Note 2) of the market settlement software with the goal of establishing a real-time balancing market. This process will entail the following seven steps:

1. Review and revise rules of market definition
2. Define system changes needed to implement market rules
3. Implementation and enhancement of hardware and software systems
4. Testing of hardware and software systems in parallel with market participant training and interface implementation
5. Testing market participant interface and system interactions
6. Market trials to test market systems and market participant interactions
7. Market implementation

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Western Farmers Electric Cooperative

Gene Argo

Executive Vice President,
President and General Manager
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Harry Dawson

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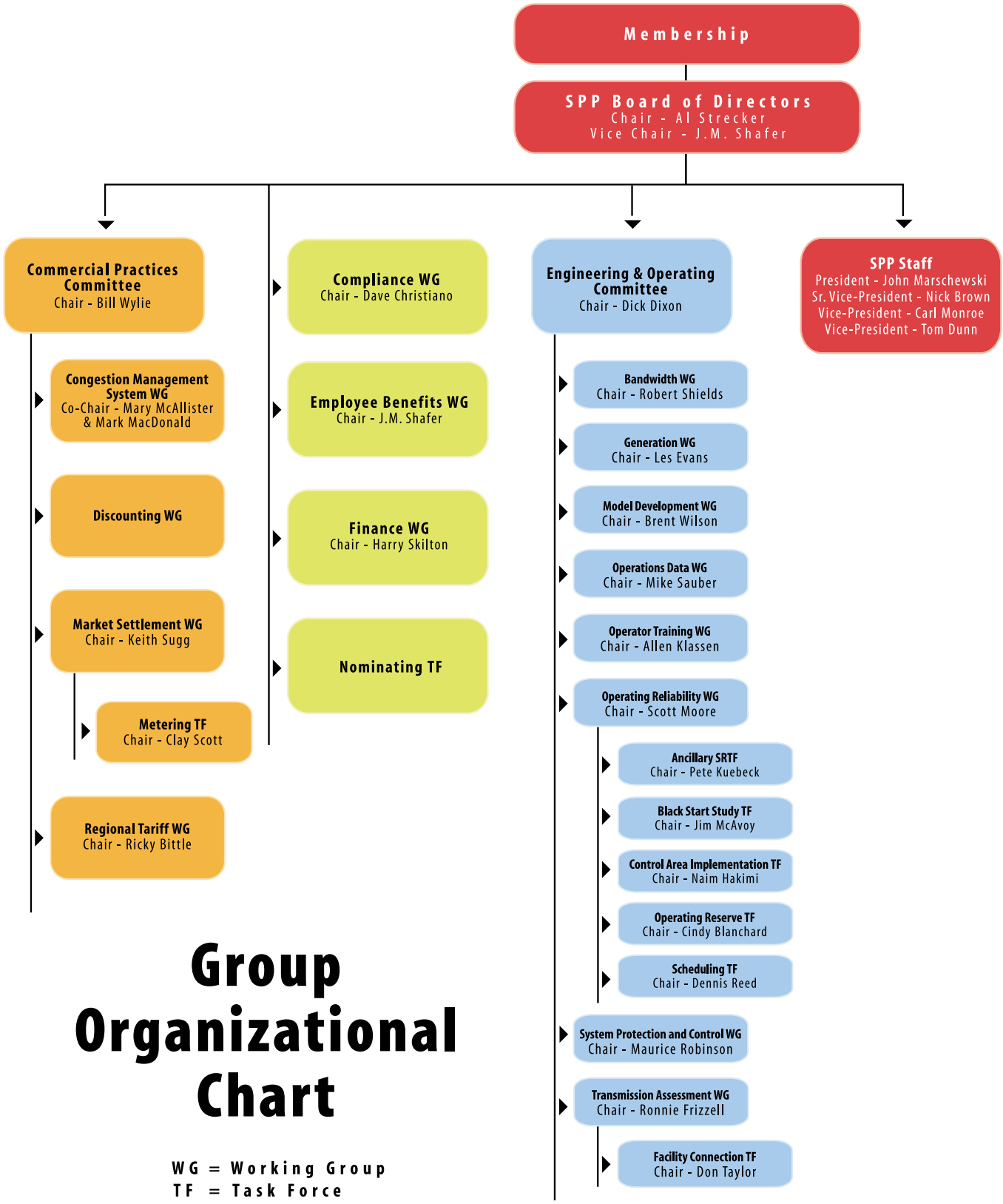
Gary Voigt

Chief Executive Officer
Arkansas Electric Cooperative Corporation

Walt Yeager *

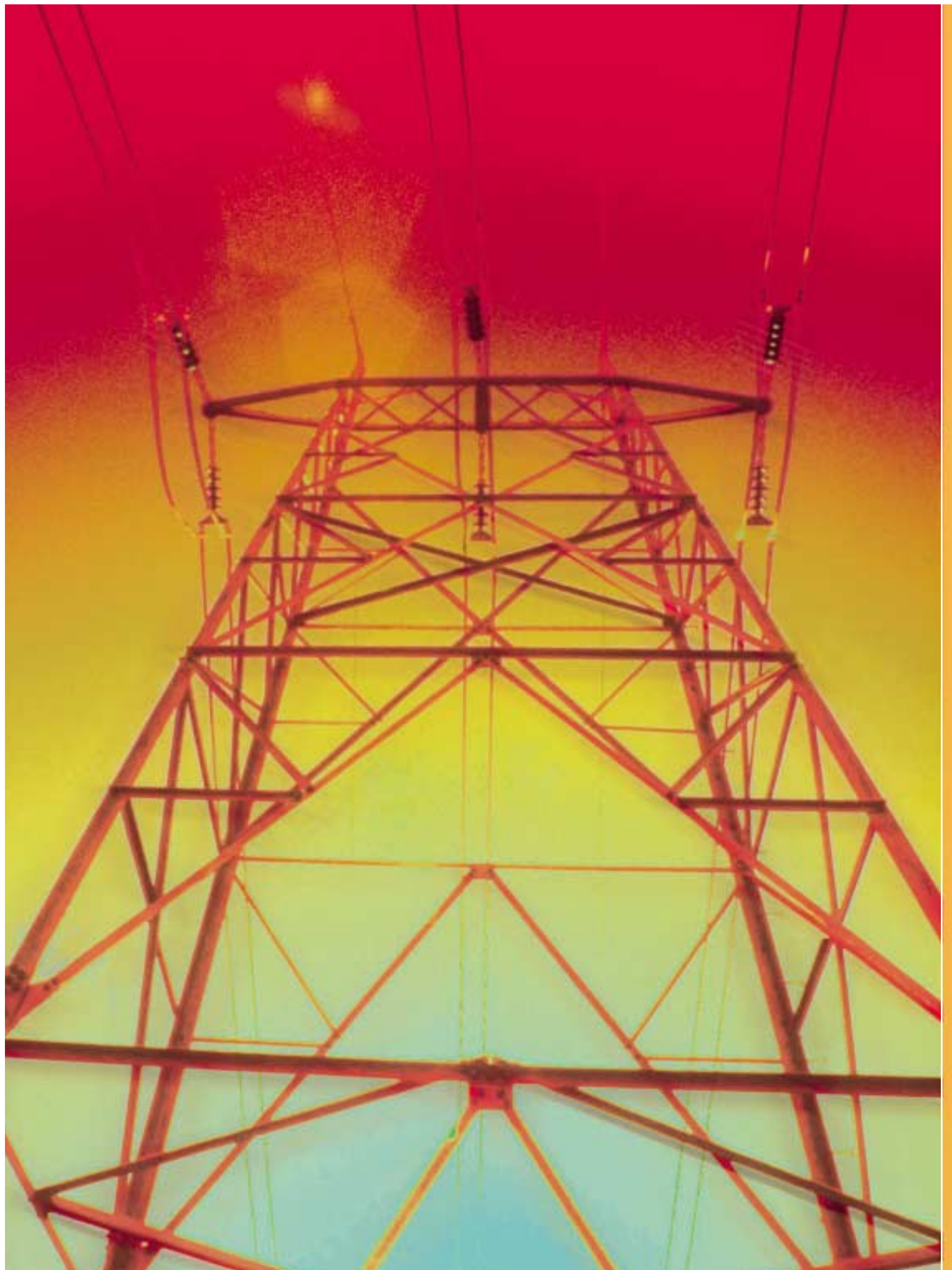
Managing Director, Market Development
Cinergy Services, Inc.

* Elected March 2003



Group Organizational Chart

WG = Working Group
TF = Task Force





Southwest Power Pool, Inc.
415 North McKinley, #800 Plaza West
Little Rock, Arkansas 72205-3020
501.664.0146

