1996 ANNUAL REPORT

Lineman Al Oregon and his family: Ida, Ryan and Megan

EL PASO ELECTRIC'S

MISSION IS TO PROVIDE

RELIABLE, COMPETITIVELY

PRICED ELECTRIC SERVICE.

WE WILL KEEP TO THE

HIGHEST STANDARDS OF

SAFETY, INTEGRITY AND

EXCELLENCE IN ALL THAT

WE DO AND WE WILL

ACHIEVE FINANCIAL

HEALTH.

Values & Objectives

Tim Miliklen, Power Generation Department

Sandra Montes, Customer Services Department

Patricia Salazar, Power Generation Department

Core Values

El Paso Electric's core values are:

Safety - Electricity is an inherently hazardous product, yet it is essential in our modern society. Producing and distributing it safely is essential to our success.

Integrity - Integrity encompasses honesty, cooperation, reliability and a firm adherence to a code of conduct which requires those qualities in all that we do.

Excellence - Performing to standards that are more demanding than anyone else's is what distinguishes companies and individuals.

Driving Force Objectives

We have identified five driving force objectives which require immediate action if we are to achieve our mission.

Safety - By providing the safest working environment possible for its employees, EPE is ensuring a productive and efficient environment. Reducing the number of work-related accidents and decreasing the amount of work time lost as a result is an important objective that will ultimately improve EPE's ability to provide efficient, reliable service.

Deleveraging - Reducing leverage will increase EPE's financial flexibility, improve its financial health and make it more competitive. EPE's efforts toward accomplishing this objective will focus on productivity and sales, as well as reducing and controlling costs. Accelerated debt reduction could result in a $36 million net interest savings over the next five years.

Competitive Service and Pricing - To succeed in a competitive market, EPE must offer top quality service at a price that is competitive.

System Reliability - EPE will provide the best quality service possible by: initiating a proactive cable replacement program; improving maintenance on operative line devices; implementing regular patrols of overhead and underground facilities; conducting visual inspections and operational testing of controlled devices; and reviewing trouble shooting and trouble response procedures, all for the purpose of enhancing system reliability.

Corporate Citizenship - EPE believes it must support civic and charitable work within the communities it serves. Our efforts in this regard include: developing a focused criteria for corporate contributions; encouraging and supporting employees to become involved in civic and charitable activities; participating in minority business programs; and giving higher preference to local vendors when purchasing goods and services.

A Message From
The Board Chairman

Dear Shareholders:

Our Company emerged from over four years in bankruptcy on February 12, 1996. Under our reorganization plan, the Company was recapitalized in a public offering of $1.2 billion of debt and $100 million of preferred stock. Shareholder equity was set at a book value of $300 million. The financial market's confidence in the success of our reorganization plan was demonstrated by a demand for our debt and preferred stock which exceeded the available supply.

Our new Board of Directors, constituted on February 13, 1996, brings a dynamic mix of business, financial, and transactional experience to bear upon the challenges which confront us. James Haines joined our Company as President and CEO on May 1. Jim brings significant financial, legal, regulatory, and operating experience to the Company.

Our Board has given clear direction to senior management: take care of customers, create opportunities from the changes occurring in the electric industry, and take advantage of every proper means to increase shareholder value. We are committed to this directive without qualification. Following shareholder approval on November 14, 1996, we have tied a significant portion of officer compensation directly to increases in shareholder value through an incentive compensation plan which pays out to officers only in the form of share options or grants, and only if cash flow and established operating goals are met.

In discussions with investors and analysts throughout the year, two specific issues always seem to be of particular interest: resumption of a common dividend and persistent mention of our Company as an acquisition target. Dividend policy, of course, is established by the Board. We believe that the Company's best use of available cash is to pay down debt. We have no present plan to resume paying a dividend.

As to being an acquisition target, our position is quite simple. We have a substantial opportunity to create extraordinary value as a stand alone company. Nonetheless, if a combination with another company ever presents a better opportunity to create the greatest value for our shareholders, we will pursue the combination. We must be mindful, though, that for such a transaction to succeed the interests of customers and employees must be satisfied as well as the primary interest of shareholders. In the meantime, nothing that we will do to create value as a stand alone company will be inconsistent with the possibility of a combination with another company.

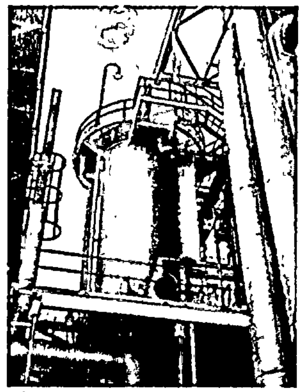
Finally, with our emergence from bankruptcy, several directors ended their service to the Company: Wilfred E. Binns, Tom Simpson, Sidney Baucom, and Curtis Hoskins served our Company with great ability and loyalty through the most difficult time in our history. On behalf of the Board and each of you, I extend them our thanks and very best wishes. David Wiggs, our former Chairman and CEO, resigned from the Board on August 8, 1996. David led our Company through this difficult time and much of the Company's success since emerging from bankruptcy is due to his effort.

Please study this report carefully. I believe you will find in it ample evidence that we are working hard to protect and increase the value of your investment in El Paso Electric.

Sincerely,

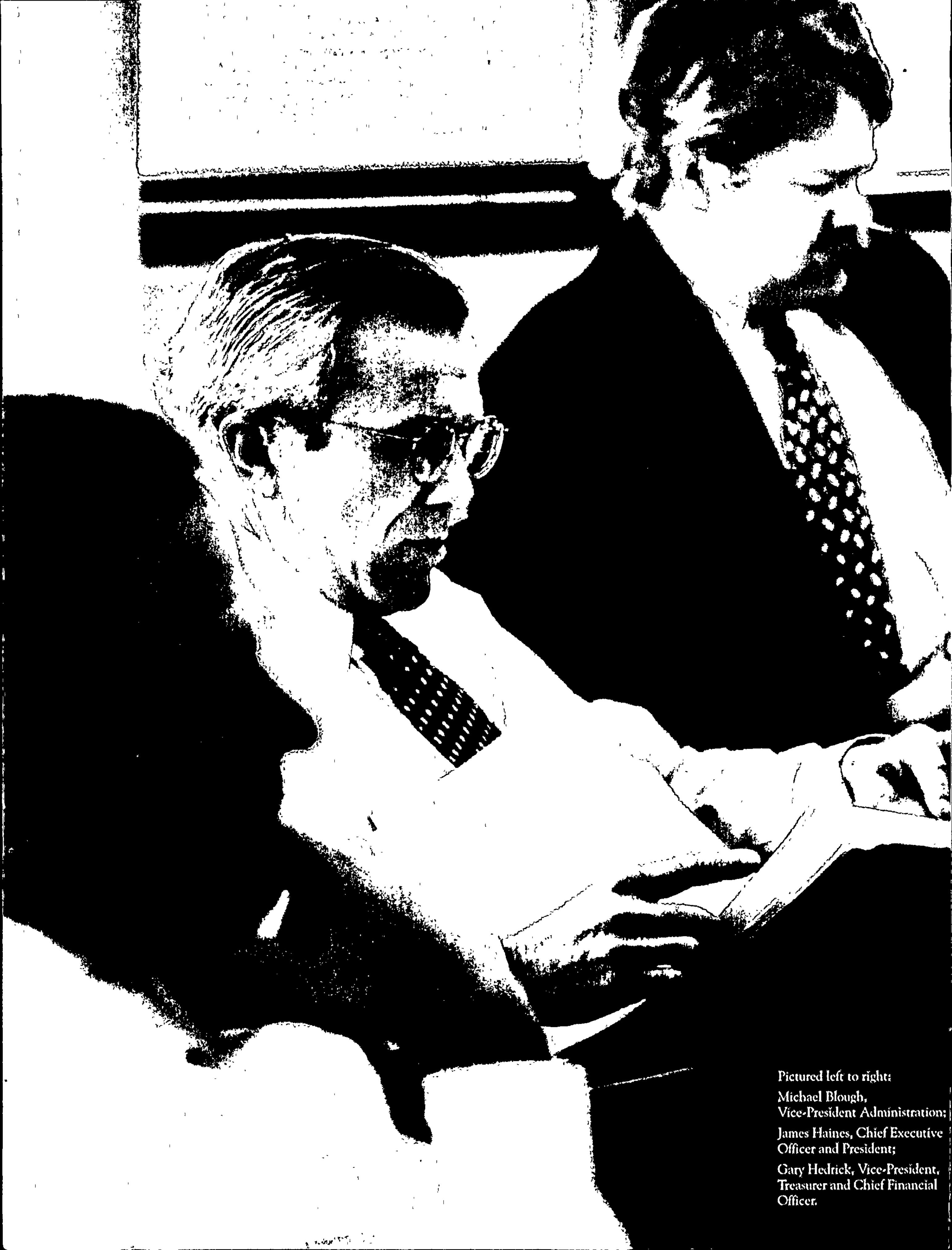
George W. Edwards
Chairman of the Board

George W. Edwards
Chairman of the Board



Rio Grande Power Plant

Glenn Nuest, Power
Generation Department



Pictured left to right:

Michael Blough, Vice-President Administration;

James Haines, Chief Executive Officer and President;

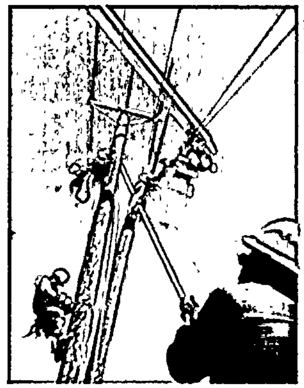
Gary Hedrick, Vice-President, Treasurer and Chief Financial Officer.

A Message From The CEO

Dear Shareholders:

El Paso Electric Company's exit from bankruptcy did not solve our problems, but it did give us a solid basis from which to attack them and to reestablish our Company as an outstanding electric utility. We are excited about the numerous achievements which got us off to a tremendous new start in 1997.

We began our existence as a new Company in February of 1996 with a commitment to aggressively reduce our debt levels. As of the date of this letter, we have already repurchased some $168 million of our first mortgage bonds. We are committed to protecting and enhancing our cash flow so that we can accelerate this deleveraging program. In that regard, during 1996 we negotiated long term rate contracts with several of our large retail customers, renewed a 200 MW power sale with the Comision Federal de Electricidad (CFE), reduced O&M costs in 1996 below 1995 levels and have budgeted yet another reduction in 1997. On the bottom line, we showed positive earnings per share in the last three quarters of 1996, $0.52 for the year.



Juan Valdez, Scott Brewer, Jannette Flores and Francisco Rodriguez with the Distribution Maintenance Crew

We are dedicated to the pursuit of excellence in our operations. This dedication resulted in our winning several industry awards during 1996 including: (i) the EPA Region VI Environmental Excellence Award, (ii) the Reliability Based Maintenance Award for Best Reporting of a New Program presented by Computational Systems Inc., (iii) the Tom Hughston Stop Shock Safety Award presented by the Southwest Electric Safety Exchange, and (iv) the 1996 Compliance Environmental Excellence Award from the State of New Mexico. Our continuing efforts in this regard saw the implementation during 1996 of a comprehensive program to improve the reliability of our transmission system and the consummation of a wholesale power marketing agreement with Enron Capital & Trade Resources Corp. All of this and more was accomplished during 1996 with fewer employees than were on the payroll in 1991.

Eduardo Rodriguez, Senior Vice-President, Customer and Corporate Services; and John Horne, Vice-President, Power Generation

Long talked about changes in the electric industry are becoming a reality. To renew our power sale contract with the CFE, we had to compete not only with other investor owned utilities but also with public power agencies and with non-regulated, non-utility power marketers. Both the Texas and New Mexico legislatures and utility commissions are studying the feasibility of retail competition. Many companies, including El Paso Electric, have begun to separate, at least operationally if not legally, their distribution, transmission, and generating functions. Some companies have even begun the process of divesting their generating facilities. Along with a rash of completed and pending consolidation transactions in the electric industry, we also see proposed combinations of electric and gas distribution companies. Many believe these transactions are essential to control access to customers and establish a larger corporate platform.

We are asked repeatedly how a small electric company, just out of bankruptcy, can hope to survive, let alone prosper, in these circumstances, particularly when it has no plans to diversify in areas not directly related to its electric utility business and no pending proposal to combine with another company. In addition, our rates are higher than the industry average and a major city in our service area, Las Cruces, is attempting to condemn our distribution facilities and create a municipal utility.

Our answer is that we have significant, competitive advantages which create a unique opportunity to build value. These advantages include our strong retail sales growth, our low incremental production costs, our stable customer base complimented by a rate freeze which covers 80% of our retail sales, our long relationship with and proximity to Mexico, and our electrical isolation from potential competition. To exploit these advantages, we are focused on five primary objectives: safety, deleveraging, competitive service and pricing, system reliability, and corporate citizenship.

Continued on next page

Certainly, when the inherently dangerous nature of our product is considered, we must always keep the safety of our employees and customers as our number one goal. Our ultimate goal is to have zero accidents. We intend to make steady progress toward that goal.

In an increasingly competitive environment, characterized by rapidly increasing business risk, a strong balance sheet is imperative. At a minimum, we must pay down the debt in our capital structure to at least the industry average of around 50 to 55%. We intend to achieve that within three to five years. Reaching that goal requires that we do more than just manage our cost of doing business. We must also increase revenues. That is the point at which our deleveraging and customer service related goals come together.

Tom Probasco, David Gutierrez and Sal Ramirez with the Power Generation Department

We are aggressively pursuing strategic alliances, such as our recently announced wholesale power marketing agreement with Enron and a non-exclusive Pilot Development Agreement with Johnson Controls (a nationally recognized energy management services company) for certain energy efficiency services provided to our retail customers. Our absolute commitment to top quality customer service, characterized by our recent formation of an energy services division, should help assure continued growth in retail sales, which over the last ten years was at an annual compound rate of 3.9%.

A significant factor in protecting revenues and assuring excellent customer service is competitive rates. Our rates are higher than the national and regional averages for investor owned utilities. Indeed, that fact in large part explains the continued efforts of Las Cruces to municipalize our distribution facilities. We recognize that we must work to achieve competitive rates. To that end, we are taking an accelerated charge to depreciation of about $31 million annually, which should bring our costs in line with the market by no later than 2005.

Ida Green, Customer Services Department

Several other factors will work in our favor as competition in electricity markets continues to develop. Although we have high rates per kWh, our dry climate permits most of our customers to air condition their homes with evaporative coolers. As a result, our residential customers have the lowest average electric bills in Texas. We are interconnected with the Western Systems Coordinating Council, not the Electric Reliability Council of Texas. As a result, we are largely isolated electrically from the rest of Texas and the Midwest and we have 32% of the revenues from our large industrial customer load under long term contracts.

Our controversy with Las Cruces is difficult and merits comment. For about the last five years, Las Cruces has been working toward an attempt to condemn certain parts of our distribution facilities and create a municipal utility. We do not believe that the law in the State of New Mexico presently permits such a condemnation. (At the writing of this report, the New Mexico legislature has passed a bill that would give the City the express authority it presently lacks. If the bill is signed by the Governor, the law will become effective and the City would be in a position to begin its condemnation process. The process could take several years to complete.) This condemnation effort appears to rest on the untenable assumption that Las Cruces could leave our system without having to compensate us for a proportionate share of strandable costs. If even a low estimate of strandable cost responsibility is included in the economic model of Las Cruces' plan, a Las Cruces municipal utility would have to increase rates in order to cover its fixed costs. On that basis, our customers in Las Cruces are better off if El Paso Electric continues to serve them. While we are in litigation with Las Cruces in several venues, our goal remains to solve this problem through negotiation and conciliation.

Finally, as shareholders, we must recognize the effort of El Paso Electric employees. Through over four years of bankruptcy, they worked hard to keep the lights on and continue a proud tradition of customer service. At times this was a thankless task as public scrutiny of the Company frequently placed it in an unfavorable light. With that behind us, our employees are now challenged by the fundamental changes sweeping through our industry. They are a great group of very good people. I assure you, they will meet that challenge.

Sincerely,

James Haines

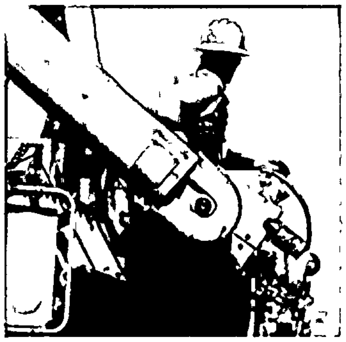
James Haines
Chief Executive Officer and President

Jannette Flores, Distribution Construction Department

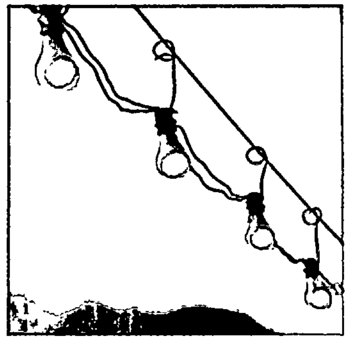
Board of Directors

And Officers

Oscar Marquez and Eduardo Gonzalez, Power Generation Department



Scott Brewer, Distribution Operations Department



Mt. Franklin Star lights

Board of Directors

George W. Edwards, Jr. (5)
Chairman of the Board
Retired in 1995. Prior to retirement, President, CEO and Director of Kansas City Southern Railway Company; Executive Vice President and Director of Kansas City Southern Industries, Kansas City, MO.

Wilson K. Cadman (5)
Retired in 1992. Prior to retirement, Chairman of the Board, President and Chief Executive Officer, Kansas Gas and Electric Company, Wichita, KS.

James A. Cardwell (7)
Chairman and Chief Executive Officer, Petro Stopping Centers, LP, El Paso, TX.

Ramiro Guzman (1)
President and Chief Executive Officer, Dickshire Distributing, El Paso, TX.

James S. Haines, Jr. (1)
Chief Executive Officer and President
El Paso Electric

James W. Harris (1)
Founder and President, Seneca Financial Group, Inc., Greenwich, CT.

Kenneth A. Heitz (1)
Partner, Irell & Manella, Los Angeles, CA.

Edward C. Houghton, IV (1)
Marketing Representative, The Financial Services Group, El Paso, TX.

Michael K. Parks (1)
President, Aurora National Life Assurance Company, Los Angeles, CA.

Eric B. Siegel (1)
Consultant, Limited Partner, Apollo Advisors/Lion Advisors, Los Angeles, CA.

Stephen N. Wertheimer (1)
Managing Director, Credit Research & Trading, Greenwich, CT.

Charles A. Yamarone (1)
Executive Vice President, Libra Investments, Inc., Los Angeles, CA.

Company Officers

James S. Haines, Jr. (1)
Chief Executive Officer and President

Eduardo A. Rodriguez (16)
Senior Vice President-Customer and Corporate Services

J. Frank Bates (24)
Vice President-Transmission and Distribution

Michael L. Blough (15)
Vice President-Administration

Gary R. Hedrick (20)
Vice President, Treasurer and Chief Financial Officer

John C. Horne (24)
Vice President-Power Generation

Robert C. McNiel (19)
Vice President-Public Affairs and Marketing

Terry Bassham (1)
General Counsel

Guillermo Silva, Jr. (18)
Secretary

( ) Years of Service

Form 10-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1996

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____ to ____

Commission file number 0-296

El Paso Electric Company
(Exact name of registrant as specified in its charter)

Texas	74-0607870
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Kayser Center, 100 North Stanton, El Paso, Texas	79901
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (915) 543-5711

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	American Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES _X_ NO __

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. YES _X_ NO __

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

As of March 20, 1997, the aggregate market value of the voting stock held by non-affiliates of the registrant was $309,772,975.

As of March 20, 1997, there were outstanding 60,239,236 shares of common stock, no par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the 1997 annual meeting of its shareholders are incorporated by reference into Part III of this report.

DEFINITIONS

The following abbreviations, acronyms or defined terms used in this report are defined below:

Abbreviations, Acronyms or Defined Terms	Terms
Agreed Order	Agreed Order of the Texas Commission entered August 30, 1995 implementing certain provisions of the Rate Stipulation
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
Bankruptcy Case	The case commenced January 8, 1992 by El Paso Electric Company in the Bankruptcy Court as Case No. 92-10148-FM
Bankruptcy Code	United States Bankruptcy Code, 11 U. S. C. §101 et seq.
Bankruptcy Court	United States Bankruptcy Court for the Western District of Texas, Austin Division
CFE	Comision Federal de Electricidad de Mexico (the national electric utility of Mexico)
Common Plant or Common Facilities	Facilities at or related to Palo Verde that are common to all three Palo Verde Units
Common Stock	Common stock, stated value $1 per share, issued by the Company in the Reorganization
Company	El Paso Electric Company
CSW	Central and South West Corporation
DOE	United States Department of Energy
Effective Date	February 12, 1996, the date the Reorganization became effective
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
Four Corners	Four Corners Generating Station
FPA	Federal Power Act
Freeze Period	Ten-year period beginning August 2, 1995, during which base rates for most Texas retail customers are expected to remain frozen pursuant to the Rate Stipulation
IID	Imperial Irrigation District, an irrigation district in Southern California
KV	Kilovolt(s)
KW	Kilowatt(s)
KWH	Kilowatt-hour(s)
Merger Agreement	Agreement and Plan of Merger dated as of May 3, 1993 among the Company, CSW and CSW Sub, as amended
MW	Megawatt(s)
MWH	Megawatt-hour(s)
New Mexico Commission	New Mexico Public Utility Commission
NRC	Nuclear Regulatory Commission
OPC	Texas Office of Public Utility Counsel
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Leases	Leases and other documents entered into in connection with a series of sale and leaseback transactions in 1986 and 1987 involving a portion of the Company's interest in Palo Verde
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
Plan	The Company's Fourth Amended Plan of Reorganization dated November 7, 1995, pursuant to which the Company emerged from bankruptcy on the Effective Date

Abbreviations, Acronyms or Defined Terms	Terms
PNM	Public Service Company of New Mexico
Predecessor Company	The Company prior to the Reorganization
Rate Stipulation	Stipulation and Settlement Agreement dated as of July 27, 1995, between the Company, the City of El Paso, OPC and most other parties to the Company's rate proceedings before the Texas Commission providing for a ten-year rate freeze and other matters
Reorganization	Reorganization and the emergence from bankruptcy by the Company pursuant to the Plan
Reorganized Company	The Company following the Reorganization
SFAS	Statement of Financial Accounting Standards
Texas Commission	Public Utility Commission of Texas
TNP	Texas-New Mexico Power Company

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PART I

Item 1. Business

General

The Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves wholesale customers in Texas, New Mexico, California and Mexico. The Company owns or has significant ownership interests in five electrical generating facilities providing it with a total capacity of approximately 1,500 megawatts. For the twelve months ended December 31, 1996, the Company's energy sources consisted of approximately 53% nuclear fuel, 32% natural gas, 7% coal and 8% purchased power.

The Company serves approximately 279,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and the City of Las Cruces ("Las Cruces"), New Mexico (representing approximately 56% and 7%, respectively, of the Company's revenues for the twelve months ended December 31, 1996). In addition, the Company sells electricity to wholesale customers, including Texas-New Mexico Power Company, the Imperial Irrigation District (a southern California electric power agency), and the Comision Federal de Electricidad de Mexico (the national electric utility of Mexico). Principal industrial and other large customers of the Company include steel production, copper and oil refining, garment manufacturing concerns and United States military installations, including the United States Army Air Defense Center at Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico.

The Company's principal offices are located at Kayser Center, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of March 3, 1997, the Company had approximately 1,100 employees, approximately 30% of whom are covered by a collective bargaining agreement that expires in June 1997.

Reorganization Under Chapter 11 of the Bankruptcy Code

Plan of Reorganization

On February 12, 1996, the Company emerged from a bankruptcy proceeding which it instituted in January 1992.

As a result of the Reorganization, the Company significantly reduced its debt and simplified its capital structure. The Company's total obligations subject to compromise (including obligations related to the Palo Verde Leases, which represented $700 million of allowed claims in the Bankruptcy Case) prior to its Reorganization was $2,007 million. Under the Plan, this debt and the Palo Verde Lease obligations were extinguished and the creditors received a combination of cash and newly issued debt and equity securities of the Reorganized Company. On December 31, 1996, the capital structure of the Reorganized Company consisted of approximately $1,046 million of long-term debt, including the long-term portion of financing and capital lease obligations, approximately $108 million of redeemable preferred stock and approximately $331 million of common stock equity.

The Company has a $100 million revolving credit facility to finance nuclear fuel purchases and to provide working capital. At December 31, 1996, approximately $46.6 million of this revolving credit facility had been drawn to finance nuclear fuel, of which approximately $20.2 million is included in the long-term debt described above. Under the Plan, all of the Predecessor Company's common and preferred stock was canceled and the holders of such securities received approximately 15% of the Reorganized Company's Common Stock and the right to receive certain litigation recoveries, if any.

In addition, on the Effective Date, the Palo Verde Leases were terminated and the Company reacquired such interests. The Company has agreed to indemnify certain parties to the Palo Verde Lease transactions against certain possible tax liabilities.

The Company's Common Stock began trading on the American Stock Exchange on February 16, 1996 under the symbol "EE."

Rate Stipulation

The Agreed Order entered on August 30, 1995 by the Texas Commission became effective on the Effective Date. The Agreed Order implemented the Rate Stipulation, dated July 27, 1995, among the Company and substantially all of the other parties to a rate proceeding in Texas. Among other things, under the Rate Stipulation, (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for ten years beginning August 2, 1995; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; and (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales. See "Regulation – Texas Rate Matters – Rate Stipulation and Agreed Order."

Accounting Treatment

The Reorganization had significant impacts on the Company's financial statements, including the creation of a new reporting entity upon emergence from bankruptcy through the application of fresh-start reporting pursuant to Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" ("SOP 90-7"). Accordingly, the Company's post-Reorganization financial statements, which reflect the application of fresh-start reporting, have not been prepared on a consistent basis with the pre-Reorganization financial statements and are not comparable in all respects to the financial statements prior to the Reorganization. The implementation of the Rate Stipulation and fresh-start reporting resulted in (i) decreased operation expense and increased depreciation expense due to the reacquisition of previously sold and leased back generation facilities and due to accelerated depreciation expense on a portion of the reorganization value assigned to certain plant assets; (ii) increased interest expense due to the changes in the Company's capital structure; and (iii) increased operating revenues related to a rate increase in the Company's Texas jurisdiction. For accounting purposes, the inception date of the Reorganized Company is deemed to be February 12, 1996. A vertical line is shown in the financial statements to separate the Reorganized Company from the Predecessor Company since the financial statements have not been prepared on a consistent basis of accounting.

Facilities

As described below, the Company currently has a net installed generating capacity of approximately 1,500 MW, consisting of an entitlement of 600 MW from Palo Verde Units 1, 2 and 3, 482 MW at its Newman Power Station, 246 MW at its Rio Grande Power Station, an entitlement of 104 MW from Four Corners Units 4 and 5, and 68 MW at its Copper Power Station.

Palo Verde Station

The Company owns a 15.8% interest in each of the three 1,270 MW nuclear generating units and Common Plant at Palo Verde, located west of Phoenix, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company ("SCE"), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde.

The NRC has granted facility operating licenses and full power operating licenses for all three units at Palo Verde for terms of forty years each. In addition, the Company is separately licensed by the NRC to own its proportionate share of Palo Verde.

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units and each Palo Verde Participant is required to fund its proportionate share of fuel, other operation, maintenance and capital costs. The Company's total monthly share of these costs was approximately $6.9 million in 1996. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

Decommissioning. Pursuant to the ANPP Participation Agreement, as well as pursuant to applicable law, the Company is required to fund its share of the estimated costs to decommission Palo Verde over the estimated service life of forty years. The Company's funding requirements are derived from periodic engineering cost estimates.

In December 1995, the Palo Verde Participants approved a study by an outside engineering firm of the cost of decommissioning Palo Verde. The 1995 study determined that the Company will have to fund approximately $229 million (stated in 1995 dollars) to cover its share of such costs. The 1995 study assumes that (i) maintenance expense for spent fuel storage will be incurred for ten years after the shutdown of the last unit (estimated to be in 2024) rather than the approximately 30 years utilized in a 1993 study; (ii) a national interim spent fuel storage facility will be available; and (iii) as a result of such national spent fuel storage facility, the amount of spent fuel stored on-site is reduced from all spent fuel assemblies to the final core plus fuel assemblies from approximately three refuelings. See "Energy Sources – Nuclear Fuel – Spent Fuel Storage."

Cost estimates for decommissioning have increased with each study, although the 1995 cost estimate is comparable to the previous cost estimate from a 1993 study (which determined that the Company would have to fund approximately $221 million, stated in 1993 dollars). The 1993 study was based on different assumptions, primarily related to the decommissioning of spent fuel. The 1993 cost estimate included an estimated cost of approximately $50 million related to on-site spent fuel storage facilities, while the 1995 study includes an estimated cost of approximately $13 million related to spent fuel. This difference in estimates is primarily due to the different timing assumptions discussed above. The 1993 estimate reflected an 84% increase from the previous estimate made in 1989, primarily due to an increase in the estimated costs associated with the permanent burial of low-level radioactive waste due to the uncertainty surrounding the availability and cost of low-level radioactive waste repositories, as discussed below.

Although the 1995 study is based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste may increase significantly. See "Disposal of Low-Level Radioactive Waste" below.

The rate freeze under the Rate Stipulation would preclude the Company from seeking a rate increase in Texas during the Freeze Period to recover increases in decommissioning cost estimates. Additionally, there can be no assurance that the Company could increase its rates in any of its other jurisdictions to recover such increased costs. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operational Prospects and Challenges."

Steam Generators. Palo Verde has experienced degradation in the steam generator tubes of each unit. The degradation includes axial tube cracking in the upper regions of the two steam generators in Unit 2 and, to a lesser degree, in Units 1 and 3. This form of steam generator tube degradation has recently been seen at other U.S. nuclear generating stations. The units also have experienced circumferential cracking at the tube sheet, a more common type of tube cracking. The axial tube cracking was discovered following a steam generator tube rupture in Unit 2 in March 1993. Since that time, APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS has stated that it believes its remedial actions have slowed the rate of tube degradation.

Each of the Palo Verde units has been inspected during regularly scheduled refueling outages and mid-cycle inspection outages. If tube cracks are detected during an inspection, the affected tubes are taken out of service by plugging. This may impair the performance of a unit if sufficient numbers of steam generator tubes are affected.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during outages of the Palo Verde units. In August 1995, APS announced that its ongoing analyses indicated that it will be economically desirable to replace the Unit 2 steam generators, which have been the most affected by tube cracking, in four to nine years. APS further stated that it expects replacement of the steam generators will be performed in conjunction with a normal refueling outage to limit incremental outage time. APS also has stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated life of 40 years (to 2025 and 2027, respectively). APS will continue to assess these steam generators periodically.

Steam generator replacement could be done through new steam generators manufactured for Palo Verde or through the purchase of existing steam generators that are compatible with Palo Verde's design. The Company believes replacement of the steam generators would require the unanimous approval of the Palo Verde Participants. The Company has not yet completed its analysis of the economic feasibility of steam generator replacement, or other options that may be available in connection with the operation of Unit 2. Also, the Company cannot predict whether it or other Palo Verde Participants will agree to replace the Unit 2 steam generators. The Company expects that if the steam generators in Unit 2 are replaced, most of such costs would be incurred between 1998 and 2005. The Company's portion of total costs associated with replacement of the Unit 2 steam generators, including replacement power costs, is currently estimated not to exceed $30 million.

The Rate Stipulation, however, precludes the Company from seeking a rate increase in Texas during the Freeze Period to recover capital costs associated with such replacement should it be necessary. It is uncertain whether the costs associated with replacing the Unit 2 steam generators would be approved by the New Mexico Commission and included in the Company's rate base in New Mexico. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operational Prospects and Challenges."

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal of radioactive waste by each state generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Despite being licensed by the State of California, the Department of the Interior has not transferred the land to the state. Following a report by the National Academy of Sciences, the Department of the Interior announced that if certain environmental conditions were implemented prior to the transfer, it was prepared to convey the land. The State of California is attempting to obtain the land through the court system without the imposition of these environmental restrictions. Although Palo Verde is estimated to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact, the opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered in the future when Arizona seeks to open its own waste repository.

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability of $200 million under federal law in the form of primary liability insurance provided by commercial insurance carriers. Additionally, the Company participates in an industry-wide retrospective assessment program, under which industry participants would be required to pay an assessment to cover any loss in excess of $200 million. The maximum assessment per reactor for each nuclear incident is approximately $79.2 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential assessment per incident is approximately $37.6 million, with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.7 billion, a substantial portion of the proceeds of which must first be applied to stabilization and decontamination. Finally, the Company has insurance against a portion of any increased cost of generation or purchased power which may result from the accidental outage of any of the three Palo Verde units if the outage exceeds 21 weeks.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of four generating units with an aggregate capacity of 482 MW. The units operate primarily on natural gas, but are also capable of operating on fuel oil.

Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate capacity of 246 MW. The units operate primarily on natural gas, but are also capable of operating on fuel oil.

Four Corners Station

The Company owns an undivided 7% interest in Units 4 and 5 at Four Corners, located in northwestern New Mexico. The two coal-fired generating units each have a generating capacity of 739 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants.

Four Corners is located on land held under easements from the federal government and a lease from the Navajo Nation that expires in 2016. Certain of the facilities associated with Four Corners, including transmission lines and almost all of the contracted coal sources, are also located on Navajo land. Units 4 and 5 are located adjacent to a surface-mined supply of coal.

Copper Power Station

The Company's Copper Power Station, located in El Paso, Texas, consists of a 68 MW combustion turbine used primarily to meet peak demands. The unit operates primarily on natural gas, but is also capable of operating on fuel oil. The combustion turbine and other generation equipment at the station were sold and leased-back by the Company in 1980 pursuant to a twenty-year lease with an option to renew for up to a seven-year period.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four major transmission lines and owns the distribution network within its retail service area. The Company is also a party to various transmission and power exchange agreements that, together with its owned transmission lines, enable the Company to obtain its energy entitlements from its remote generation at Palo Verde and Four Corners.

Springerville-Diablo Line. The Company owns a 310-mile, 345 KV transmission line from Tucson Electric Power Company's ("TEP") Springerville Generating Plant near Springerville, Arizona to the Luna Substation near Deming, New Mexico, and to the Diablo Substation near Sunland Park, New Mexico, providing an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners.

Arroyo-West Mesa Line. The Company owns a 202-mile, 345 KV transmission line from the Arroyo Substation located near Las Cruces, New Mexico to PNM's West Mesa Substation located near Albuquerque, New Mexico. This is the delivery point for the Company's generation entitlement from Four

Corners, which power is transmitted to the West Mesa Substation over approximately 150 miles of transmission lines owned by PNM. This transmission line also carries power from the region to the west and north of Four Corners, where the Company has a major interconnection with the other Four Corners Participants.

Greenlee-Newman Line. The Company owns undivided interests in a 196-mile, 345 KV transmission line from the Newman Power Station to TEP's Greenlee Substation in Arizona. This line provides an interconnection with TEP for delivery of the Company's entitlements from Palo Verde and, if necessary, Four Corners.

AMRAD-Eddy County Line. The Company owns an undivided 66.7% interest in a 125-mile, 345 KV transmission line from the AMRAD Substation near Oro Grande, New Mexico to the Company's and TNP's high voltage direct current terminal at the Eddy County substation near Artesia, New Mexico. This terminal enables the Company to connect its transmission system to that of Southwestern Public Service Company ("SPS"), providing the Company with access to power markets to the east.

Issues Regarding Operation of Transmission System

The Company experienced three system outages between September 19, 1995 and October 21, 1995 and a fourth system outage on March 29, 1996. The four outages were caused by different combinations of factors. The first three outages involved faults on one of the Company's transmission lines, followed by relay failures that resulted in the loss of a second Company transmission line and the subsequent inability of the Company's load shedding programs to prevent general system instability. The fourth outage was caused by a fault on a neighboring utility's transmission line followed by relay failures on the Company's transmission system that caused the loss of two of the Company's transmission lines. Although the Company was able to stabilize its system for a brief period of time following the loss of the two lines through a controlled load-reduction scheme, a system outage occurred after a third Company line tripped out of service.

In response to the outages, the Company has undertaken numerous remedial measures, including the replacement of certain relay equipment, the reconfiguration of structures that support certain high voltage wires and the installation of two new load shedding systems, to lessen the likelihood that future transmission faults will cause general system instability and widespread outages. While performing these measures between mid-November 1995 and early January 1996, the Company materially reduced the amount of power imported into the El Paso load center in order to reduce stress on the system in the event of a fault on these lines. Operation in this mode resulted in increased operating costs of approximately \$2.3 million due to the use of higher cost power from local generating plants and the necessity of purchasing power from other utilities to supply the Company's customers. While the Company can operate in this mode during cool weather months when demand is low, the Company requires its full allocation of power from its remote generating sources to meet the normal demands of customers and contractual commitments to Mexico in the warmer months.

The Company believes that its remedial efforts have solved the outage problem, and the Company has continued to import normal amounts of power over its transmission lines since January 1996. If the Company experiences further difficulties with its system, it could be required to adopt costly operating procedures until appropriate remedial efforts are implemented, and the Company might not be able to deliver sufficient power to meets its contractual obligations or to fulfill its statutory obligation to serve customers. In addition, the Texas and the New Mexico Commissions, which have monitored the

Company's efforts to address the outages, could impose penalties or other sanctions or deny the Company recovery of certain fuel and/or purchased power costs related to the Company's decision to reduce power imports during the period referenced above. The Company's capital expenditure budget does not provide for major expenditures relating to the transmission system, and certain of the Company's debt obligations restrict or prohibit major unanticipated capital expenditures. In addition, the cost of constructing new transmission facilities could not be charged to Texas retail customers under the Rate Stipulation, and the Company cannot assure that it would be able to charge any of its customers outside of Texas for such construction costs.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Because construction of new facilities is subject to standards imposed by environmental regulation, substantial expenditures may be required to comply with such regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company. See Part II, Item 8, "Financial Statements and Supplementary Data – Note J of Notes to Financial Statements."

PCB Treatment, Inc. The Company received a request from the U.S. Environmental Protection Agency ("EPA") to participate in the remediation of polychlorinated biphenyls ("PCBs") at two facilities in Kansas City, Missouri, which had been operated by PCB Treatment, Inc. ("PTI"). The Company's manifests indicate that between 1982 and 1986, the Company sent 23 shipments of PCBs or PCB-containing electric equipment ("PCB Equipment") to PTI, accounting for approximately 2 to 3%, by weight, of the PCBs and PCB Equipment received at that site by PTI. Presently, PTI has discontinued operations and the EPA has determined that PTI's abandoned facilities require remediation.

The Company and the PTI Steering Committee, which consists of the largest generators of the PCBs sent to PTI, have executed a settlement agreement. In consideration for the payment of approximately $0.2 million, the settlement agreement excuses any further liability to the Steering Committee by the Company and indemnifies the Company for any liabilities to other parties as may be asserted in the future.

The Company may still face liability for possible deliveries of PCBs by PTI to a third site which is also subject to remedial action by the federal authorities, except to the extent that those PCBs were transferred from the first site. The Company's records do not indicate any deliveries of PCBs to this third site. Management believes the Company is unlikely to face substantial unindemnified liabilities associated with this third site.

Coal Mine Reclamation. The Company has been informed by APS that the Company's estimated financial obligation for coal mine reclamation at Four Corners is not being fully reflected in the costs for which the Company is billed. APS, the operating agent of Four Corners, is performing an analysis to establish an appropriate revised cost estimate. Based on preliminary estimates from APS and the coal provider, the Predecessor Company recorded a liability of approximately $12 million which reflects the present value of the estimated future costs of reclamation at the Effective Date to reflect its share of the coal mine reclamation obligation.

Construction Program

The Company has no current plans to construct any new generating facilities through at least 2004. Utility construction expenditures reflected in the table below consist primarily of expanding and updating the electric transmission and distribution systems and the cost of improvements at Palo Verde. The Company's estimated cash construction costs for 1997 through 2000 are approximately $206 million. Actual costs may vary from the construction program estimates set forth below. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1) (In millions)		By Function (In millions)	
1997	$ 50	Production (1)	$ 53
1998	52	Transmission	20
1999	50	Distribution	102
2000	54	General	31
Total	$ 206	Total	$ 206

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(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources – Nuclear Fuel."

Energy Sources

General

The following table summarizes the percentage contribution of nuclear, natural gas, coal, and purchased power to the total KWH energy mix of the Company.

Power Source	Years Ended December 31, 1996	1995	1994
Nuclear	53%	53%	45%
Natural Gas	32	30	32
Coal	7	9	9
Purchased Power	8	8	14
Total	100%	100%	100%

Fuel and purchased power costs are generally passed through directly to customers in Texas and New Mexico pursuant to currently applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the appropriate commission to establish the applicable fuel rate to be charged customers and to determine whether a refund or surcharge based on such historical costs and revenues is necessary. See "Regulation – Texas Rate Matters – Fuel," " – New Mexico Rate Matters – Fuel" and Part II, Item 8, "Financial Statements and Supplementary Data – Note C of Notes to Financial Statements."

Nuclear Fuel

The Palo Verde Participants have contracts for uranium concentrate which should be sufficient to meet Palo Verde's operational requirements through at least 2000. Spot purchases in the uranium market will also be made, as appropriate. The Palo Verde Participants have contracted for up to 100% of conversion services required through 2000. The Palo Verde Participants have an enrichment services contract with the United States Enrichment Corporation ("USEC") which obligates USEC to furnish the enrichment services required for the operation of the three Palo Verde units through 2002, with an option for five additional years. A new contract provides fuel assembly fabrication services for each Palo Verde unit through 2016.

Spent Fuel Storage. The spent fuel storage facilities at Palo Verde have sufficient capacity to store all fuel expected to be discharged from normal operation of all of the Palo Verde units through at least 1999. If necessary, more spaces in the existing fuel pool may be approved for use by the NRC which would extend storage capacity through 2001, or, if more economical, alternative storage facilities can be constructed on-site.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987, the DOE is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. In November 1989, the DOE reported that such disposal facilities will not be in operation until 2010. Subsequent judicial decisions require the DOE to start disposing of spent nuclear fuel no later than January 31, 1998, although the DOE has told APS that it will not meet this deadline. As a result, under the DOE's current criteria for shipping allocation rights, it is estimated that Palo Verde could not ship spent fuel to the DOE permanent disposal facility until approximately 2025. APS has indicated that alternative interim spent fuel storage methods will be available on-site or off-site for use by Palo Verde to allow its continued operation and to store spent fuel safely until shipments to the DOE's permanent disposal facility begin. The Texas Commission is currently evaluating what, if any, action it should take with regard to payments made by the Company to the DOE for funding of the DOE's obligation to start accepting spent nuclear fuel by January 31, 1998.

Nuclear Fuel Financing. Pursuant to the ANPP Participation Agreement, the Company has an undivided interest in nuclear fuel purchased in connection with Palo Verde. On the Effective Date, the Company and Texas Commerce Bank, as trustee, entered into a $100 million credit facility with Chemical Bank that includes a portion for working capital requirements and up to $60 million for the financing of nuclear fuel. At December 31, 1996, approximately $46.6 million had been drawn to finance nuclear fuel. The Company also entered into a purchase contract with the trustee related to the financing of nuclear fuel purchases. Under the terms of the documents related to the nuclear fuel financing, the trust borrows under the credit facility amounts sufficient to purchase and prepare nuclear fuel for use. The Company is obligated to repay borrowings by the trustee under the facility, which obligation is secured by Collateral Series Bonds, and is required to make quarterly payments to the trust for the heat energy produced by the nuclear fuel and used by the Company. For financial reporting purposes, the Company reports the assets and liabilities of the trust as its own.

Natural Gas

In 1996, the Company's natural gas requirements at the Rio Grande Power Station were met solely with spot natural gas purchases from various suppliers. Interstate gas is delivered under a firm ten year transportation agreement, which expires in 2001. Based on the current availability of economic and reliable spot natural gas, the Company anticipates it will continue to purchase spot natural gas for the Rio Grande Power Station for the near term. To complement the spot purchases, the Company has entered into a one-year gas supply contract with Cook Inlet for 1997. For the long term, the Company will evaluate the availability of spot natural gas versus other supplies in obtaining a reliable and economical supply for the Rio Grande Power Station.

In 1996, the natural gas requirements for the Newman and Copper Power Stations were supplied and transported pursuant to an intrastate natural gas contract which expired December 31, 1996. The Company has an agreement with KN-Energy to supply gas to the Newman and Copper Power Stations beginning in 1997 through 2001. To augment this contract, the Company procured a second natural gas supply agreement with U.S. Gas Transportation, Inc., which runs through 2001.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. Management believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements for its useful life.

Purchased Power

To supplement its own generation, the Company has a firm power purchase agreement with SPS for a minimum of 35 MW for 1997.

Operating Statistics

	December 31, 1996 (A)	1995 (B)	1994 (B)
Operating revenues (In thousands):			
Base revenues:			
Retail:			
Residential	$ 141,719	$ 128,295	$ 129,869
Commercial and industrial, small	138,910	128,715	126,450
Commercial and industrial, large	43,483	40,870	39,754
Sales to public authorities	65,534	59,613	59,811
Total retail	389,646	357,493	355,884
Wholesale sales for resale	71,254	74,557	75,750
Total base revenues	460,900	432,050	431,634
Fuel revenues and economy sales	114,042	68,823	101,076
Other	3,981	3,744	4,050
Total operating revenues	$ 578,923	$ 504,617	$ 536,760
Number of customers (End of year):			
Residential	250,209	245,245	240,368
Commercial and industrial, small	25,304	24,615	23,857
Commercial and industrial, large	102	89	80
Other	3,711	3,674	3,470
Total	279,326	273,623	267,775
Average annual use and revenue per residential customer:			
KWH	6,238	6,057	6,313
Revenue	$ 661.04	$ 578.88	$ 644.82
Average revenue per KWH:			
Residential	10.60 ¢	9.56 ¢	10.21 ¢
Commercial and industrial, small	9.21	8.15	8.88
Commercial and industrial, large	4.85	4.34	5.01
Energy supplied, net, KWH (In thousands):			
Generated	7,920,675	7,439,404	7,018,423
Purchased and interchanged	711,791	584,853	1,051,251
Total	8,632,466	8,024,257	8,069,674
Energy sales, KWH (In thousands):			
Retail:			
Residential	1,545,274	1,473,349	1,500,426
Commercial and industrial, small	1,779,986	1,754,176	1,721,736
Commercial and industrial, large	1,216,941	1,121,329	1,092,028
Sales to public authorities	1,110,706	1,068,048	1,081,850
	5,652,907	5,416,902	5,396,040
Wholesale:			
Sales for resale	1,753,553	1,646,357	1,925,671
Economy sales	757,999	538,102	320,026
Total sales	8,164,459	7,601,361	7,641,737
Losses and company use	468,007	422,896	427,937
Total	8,632,466	8,024,257	8,069,674
Native system:			
Peak load, KW	1,105,000	1,088,000	1,093,000
Net generating capacity for peak, KW	1,500,000	1,500,000	1,497,000
Load factor	63.4 %	61.6 %	61.1 %
Total system:			
Peak load, KW	1,387,000	1,374,000	1,365,000
Net generating capacity for peak, KW	1,500,000	1,500,000	1,497,000
Load factor	64.2 %	62.0 %	63.7 %

(A) Financial data is based on the combined results for the Predecessor Company for the period January 1, 1996 to February 11, 1996 and the Reorganized Company for the period February 12, 1996 to December 31, 1996.

(B) Predecessor Company.

Regulation

Texas Rate Matters

The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services in Texas and jurisdiction over certain activities of the Company.

Rate Stipulation and Agreed Order. The Company's rates for its Texas jurisdictional customers are governed by the Agreed Order, which became effective on the Effective Date. The Agreed Order implemented certain provisions of the Rate Stipulation and set rates consistent with the Rate Stipulation. Among other things, under the Rate Stipulation: (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for the Freeze Period; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) the Company's reacquisition of the Palo Verde leased assets is deemed to be in the public interest; (vi) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vii) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

Neither the Rate Stipulation nor the Agreed Order deprives the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined in the Agreed Order that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Rate Stipulation (other than the General Counsel, OPC and the State of Texas) agreed not to seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Rate Stipulation retain all rights provided in the Rate Stipulation, their rights to participate as a party in any proceeding related to the merger, as well as the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings. See "Recent Changes in Utility Regulation."

Fuel. The Company must periodically reconcile its Texas fuel costs pursuant to Texas Commission rules. The Company has not filed a reconciliation, which must contain not less than twelve months nor more than thirty-six months of reconcilable data for any period since June 1995. In a reconciliation, revenues that the Company collected from Texas customers under its fixed fuel factor are reconciled with the expenses for fuel and purchased power actually incurred by the Company for the period covered by the reconciliation. Differences between revenues collected and expenses incurred are subject to a refund to customers (in the case of an overrecovery of fuel costs) or surcharge (in the case of an underrecovery of fuel costs). The Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the recovery of expenses on the basis of unreasonable or improper fuel and purchased power costs.

Higher natural gas prices began in December 1996 and continued in the first quarter of 1997. These higher natural gas prices will increase the Company's underrecovered fuel costs, which will be reviewed in the next Texas fuel reconciliation.

Palo Verde Performance Standards. The Texas Commission has established performance standards for the operation of Palo Verde, pursuant to which Palo Verde is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. There are five performance bands based around a target capacity factor of 70%. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission could reconsider the rate treatment of Palo Verde, regardless of the provisions of the Rate Stipulation. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Based upon the formula for calculating the performance standards in Texas, the Company does not believe a performance penalty will be assessed for the year ended December 31, 1996.

New Mexico Rate Matters

The New Mexico Commission has jurisdiction over the Company's rates and services in New Mexico and jurisdiction over certain activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. Current base rates in New Mexico were established in 1990 and have not increased. The Company does not have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation.

Pending Rate Case. In October 1996, the New Mexico Commission issued an order in Case No. 2722, requiring the Company to answer certain ratepayer complaints and to file a rate filing package, including cost of service data and supporting testimony. On March 3, 1997, the Company filed all of the rate filing package data required by the Commission's order with the Commission. Although the Company's filing demonstrates a revenue deficiency of approximately $8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Fuel. The Company is required to file an annual fuel report and an annual Palo Verde performance standards report, discussed below, with the New Mexico Commission by January 31 of each year for the preceding calendar year. The Company requested and received two extensions of time and filed these reports on March 24, 1997. The Company's filing reflects a significant increase in the monthly fuel charge to be effective with bills rendered on or after May 1, 1997. This increase is necessary because of significant increases in the spot price of natural gas which have caused the Company to underrecover its fuel costs in New Mexico by approximately $2.0 million for the year ended December 31, 1996. The recovery of this amount, coupled with projected higher gas costs for 1997, results in an increase in the proposed 1997 fuel factor of approximately 50% over the present factor. There can be no assurance that the Commission will accept the Company's proposed fuel factor. As in Texas, interested parties are allowed to intervene and challenge the recoverability of expenses as unreasonable or imprudent. Any significant disallowance of recovery could have a material adverse effect on the Company's financial results.

Palo Verde Performance Standards. The New Mexico Commission has established performance standards for the operation of Palo Verde, pursuant to which the entire Palo Verde station is evaluated annually to determine if its achieved capacity factor allows the Company to claim a credit or subjects the Company to a penalty. Because Unit 3 is not included in the Company's New Mexico rate base, any penalty or credit calculated on a total station basis is limited to two-thirds of such penalty or credit. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the annual capacity factor is 35% or less, the New Mexico Commission is required to initiate a proceeding to reconsider the rate base treatment of Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. For the year ended December 31, 1996, the Palo Verde station capacity factor was 86.20%. This capacity factor resulted in the Company's entitlement to a credit. However, the Company is voluntarily foregoing collection of this credit to partially mitigate the increase in the proposed New Mexico fuel factor, discussed above.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The Company is subject to regulation by the FERC in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

The Company has a long-term firm power sales agreement with IID providing for the sale of 100 MW of firm capacity and 50 MW of contingent capacity through April 2002. The agreement generally provides for level sales prices over the life of the agreement. The Company has a firm power sales agreement with TNP, providing for sales to TNP in the minimum amount of 25 MW through 2002. Sales prices are essentially level for the remaining life of the agreement. Rate tariffs currently applicable to IID and TNP contain fuel and purchased power cost adjustment provisions designed to recover the Company's fuel and purchased power costs.

In July 1996, the Company filed its open access transmission tariffs (Docket No. OA96-200-000) in compliance with Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* ("Order No. 888"), covering network and point-to-point transmission services and the six specifically required ancillary services. Several parties, including Las Cruces, other utilities and several wholesale power marketers intervened and filed protests to the Company's tariffs. Issues raised by the intervenors included rates and the terms and conditions of the Company's tariffs, including the treatment and costs related to certain facilities making access to the CFE more available to parties other than the Company. In February 1997, the Company entered into a stipulated agreement among the various parties settling all issues related to Docket No. OA96-200-000. Under the settlement the Company will provide transmission service, to the extent transmission capacity is available, to any party for firm or interruptible service to the CFE until the earlier of the end of 1998 or the date the FERC rules on the complaint filed by Enron. See Item 3, "Legal Proceedings – Transmission Service to Mexico."

In December 1996, Las Cruces filed a request at the FERC for a determination that Las Cruces would have no stranded cost obligation to the Company in the event the city leaves the Company's system and operates its own municipal utility. The Company calculated Las Cruces' stranded cost obligation to be approximately $234 million. The FERC is expected to establish a procedural schedule for discovery and hearings in this matter. The Company is unable to predict the outcome of this proceeding or the impact it may have on the Company. See Item 3, "Legal Proceedings – Litigation with Las Cruces."

Also in December 1996, SPS filed a request for the issuance of an order by the FERC requiring the Company to accept as a "completed application" for service under the Company's open access transmission tariff a September 1996 request by SPS for service that may be needed for SPS to deliver electricity to a newly-formed Las Cruces municipal electric system. The Company stated in response to that request that SPS had failed to provide certain information required to be submitted by persons seeking service under its open access transmission tariff. The Company has asked that the proceedings initiated by Las Cruces and by SPS, respectively, be consolidated. Both matters are currently pending before the FERC.

Department of Energy. The DOE traditionally regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. In addition, the DOE is authorized to assess operators of nuclear generating facilities for a share of the costs of decommissioning the DOE uranium enrichment facilities.

In October 1996, the FERC issued an order requiring the Company to provide Enron Power Marketing, Inc., a wholesale power marketer, with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction.

Promptly after the issuance of the FERC order, Enron asked the DOE to exercise its authority over Presidential Permits relating to construction of border-crossing transmission facilities and over export authorizations issued to the Company and to Enron to require transmission access for delivery of electricity to the CFE in Mexico. Pursuant to Enron's request, the DOE, on October 30, 1996, issued a Notice and Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties with respect to Presidential Permits and export authorizations issued to the Company. The Company has filed responses to Enron's request at both the FERC and the DOE in which it has asserted that the DOE has no authority to require transmission of electric energy for delivery to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder during 1997, if someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position, which remains that under the current law the provision of such access is not required. Neither the FERC nor the DOE has taken any final action on this matter.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards and has authority to conduct environmental reviews pursuant to the National Environmental Policy Act.

Other Wholesale Customers

The primary term of the Company's previous five year sales agreement for firm capacity and associated energy to the CFE terminated December 31, 1996. In September 1996, the CFE issued a request for proposals for replacement power for 1997. The Company submitted a bid and was ultimately selected by the CFE to provide varying amounts of power during 1997 ranging from 120 to 200 MW. Since the CFE load provided by the Company will be isolated from the rest of the CFE system, the Company is also providing the CFE with the flexibility to increase its power deliveries up to 5% above its monthly contract capacity level in order to meet its customer power requirements. The price is stable throughout the term of the agreement and includes charges for capacity and energy as well as transmission and any required ancillary services. Under the new agreement with the CFE, revenues in 1997 related to power sa CFE are expected to be lower than revenues recorded in 1996. The agreement requires payment in States dollars. See Item 3, "Legal Proceedings – Transmission Service to Mexico" and Part II, Ite "Financial Statements and Supplementary Data – Note M of Notes to Financial Statements."

Recent Changes in Utility Regulation

General. The electric utility industry faces increasing pressure to become more competitive as legislative, regulatory, economic and technological changes occur. Federal legislation, as well as legislative and regulatory initiatives in various states and proposed initiatives in Texas and New Mexico, encourages competition in the Company's service area for electricity generation among electric utility and non-utility power producers. Together with increasing customer demand for lower-priced electricity and other energy services, these measures have accelerated the industry's movement toward more competitive pricing and cost structures. Such competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets, as well as the cost of operating these assets. This issue is particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flows and financial condition of the Company, or that the Company will be able to sustain retail rates at the levels established by the Rate Stipulation during the Freeze Period.

Of particular importance to the Company is the issue of ultimate recoverability of costs previously found by regulatory authorities to be reasonable and prudent, but which at the same time are higher than would be recovered under immediate, full competition (i.e., stranded costs). Across the industry, as well as at the state level, there is much discussion and debate on this issue. At this time, there appears to be no clear solution. At the federal level, the FERC has announced, through a formal rulemaking, its intention to allow 100% recovery of all legitimate verifiable stranded costs attributable to FERC jurisdictional customers. Texas and New Mexico are engaged in various activities, at the commission and legislative level, which are attempting to address the issue of stranded cost recovery from customers subject to state legislation.

FERC. In April 1996, pursuant to its authority under Sections 205 and 206 of the FPA, the FERC issued its Order No. 888. Order No. 888 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to (i) file open access transmission tariffs containing minimum terms and conditions of non-discriminatory service and (ii) take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. Additionally, Order No. 888 permits public utilities to seek recovery of legitimate, prudent and verifiable stranded costs and provides a mechanism for the recovery of such costs. Order No. 888 also provides for recovery of costs associated with former power customers and new municipally-owned entities becoming transmission-only customers as a result of providing open access transmission if the utility had a reasonable expectation of continuing to provide service to the departing customer. Order No. 888 established criteria under which stranded costs will be evaluated for contracts entered into prior to July 11, 1994, and for stranded costs resulting from the formation of any new municipal utilities. Recovery of stranded costs under contracts entered into after July 10, 1994, will be governed by the terms of those contracts.

In April 1996, the FERC also issued Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct* ("Order No. 889"). Order No. 889 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to develop and maintain an Open Access Same-Time Information System that will give existing and potential transmission users access to transmission related information on a basis consistent with that available to a utility's employees engaged in the buying and selling of power. Order No. 889 further requires public utilities to separate their transmission and generation marketing functions and communications and adopt standards of conduct ensuring that all open access transmission customers are treated in a non-discriminatory manner.

Texas. In February 1996, the Texas Commission adopted a rule governing wholesale transmission access, as required by recent Texas legislation. The Texas Commission does not have jurisdiction over the Company's wholesale transactions. However, the rule required the Company to file its FERC-approved open access transmission tariffs with the Texas Commission to certify compliance with the Texas legislation.

During 1996, pursuant to the directives of the Texas Legislature in legislation passed in 1995, the Texas Commission conducted projects to evaluate the (i) scope of competition in the electric industry in Texas and (ii) potential for stranded investment, procedures for allocating stranded costs and acceptable methods of stranded cost recovery. The Texas Commission's report consolidating the two projects was issued in January 1997. While it recommended a careful and deliberate approach to continued expansion of competition in the Texas electric market, ultimately leading to retail competition with certain safeguards, it also recommended against any legislation that would introduce broad based retail competition before 2000. The Texas Commission quantified the potential "excess of cost over market" ("ECOM") at both wholesale and retail levels under several scenarios. With respect to the Company's potential for stranded costs, the Texas Commission estimated no wholesale ECOM, and estimated retail ECOM ranging from a high of $1.3 billion to a low of $781.0 million, with an expected value of $1.1 billion, assuming full retail access in 1998. The Company cannot determine at this time the effects that would occur, including any possible effects on the Rate Stipulation, as the result of any broad based competition legislative action, if any, implemented in 1997.

New Mexico. The New Mexico Commission initiated a notice of inquiry regarding competition and the restructuring of regulation of the electric industry in 1996. The New Mexico Commission received comments from numerous parties representing various interests and conducted workshops in an attempt to arrive at a consensus with respect to the need for regulatory change, the nature of such change and the timing/transition of any changes. No consensus was reached by the participants. With respect to stranded costs, the New Mexico Commission applied the same ECOM model that was developed for Texas. The Company's New Mexico ECOM calculation ranged from a high of $248 million to a low of $173 million. The Company also provided the New Mexico Commission with its calculation of stranded costs for New Mexico pursuant to FERC Order No. 888, which equaled $364 million.

Executive Officers of the Company

Name	Age	Current Position and Business Experience
James S. Haines	50	Chief Executive Officer, President and Director since May 1996; Executive Vice President and Chief Operating Officer of Western Resources, Inc. from June 1995 to May 1996; Executive Vice President and Chief Administrative Officer of Western Resources, Inc. from April 1992 to June 1995.
Eduardo A. Rodriguez	41	Senior Vice President – Customer and Corporate Services since August 1996; Senior Vice President since January 1994; Vice President from April 1992 to January 1994; General Counsel from 1988 to August 1996; Secretary from January 1989 to January 1994.
J. Frank Bates	46	Vice President – Transmission and Distribution since August 1996; Vice President – Operations from May 1994 to August 1996; Vice President – Customer Services Texas Division from June 1989 to May 1994.
Michael L. Blough	41	Vice President – Administration since August 1996; Vice President since May 1995; Controller and Chief Accounting Officer from November 1994 to August 1996; Assistant Vice President – Financial Planning from September 1990 to November 1994.
Gary R. Hedrick	42	Vice President, Treasurer and Chief Financial Officer since August 1996; Treasurer since March 1996; Vice President – Financial Planning and Rate Administration from September 1990 to August 1996.
John C. Horne	48	Vice President – Power Generation since August 1996; Vice President – Power Supply from May 1994 to August 1996; Vice President – Transmission Systems Division from August 1989 to May 1994.
Robert C. McNiel	50	Vice President – Public Affairs and Marketing since August 1996; Vice President – New Mexico Division from December 1989 to August 1996.
Terry Bassham	36	General Counsel since August 1996; Shareholder with Clark, Thomas & Winters, P.C. from May 1993 to August 1996; Shareholder with Moreno, Fry & Bassham from February 1992 to May 1993; Shareholder with Kemp, Smith, Duncan & Hammond, P.C. for more than one year prior to February 1992.
Guillermo Silva, Jr.	43	Secretary since January 1994; Assistant Secretary from June 1989 to January 1994.

The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors.

Item 2. Properties

The principal properties of the Company are described in Item 1, "Business," and such descriptions are incorporated herein by reference. Transmission lines are located either on private rights-of-way, easements or on streets or highways by public consent. See Part II, Item 8, "Financial Statements and Supplementary Data – Note H of Notes to Financial Statements" for information regarding encumbrances against the principal properties of the Company.

Item 3. Legal Proceedings

Litigation with Central and South West Corporation

In May 1993, the Company entered into the Merger Agreement, pursuant to which the Company would have been acquired by CSW. In June 1995, CSW terminated the Merger Agreement. In response, the Company filed a complaint against CSW in the 205th Judicial District Court of El Paso County, Texas, alleging, among other claims, breach of contract, breach of duty of good faith and fair dealing, breach of fiduciary duty, business disparagement, tortious interference with contract and fraud in the inducement. The Company sought an unspecified amount of damages, punitive damages, attorneys' fees and costs. In June 1995, CSW filed an adversary proceeding against the Company in the Bankruptcy Court seeking the recovery of termination fees of $25 million, approximately $3.7 million in attorneys' fees and expenses that CSW claims it advanced on behalf of the Company in certain regulatory proceedings, and $25 million for the alleged violation of the Merger Agreement's no-solicitation provisions. All of the claims by both parties were tried in the Bankruptcy Court. The trial concluded on January 30, 1997, and the matter has been taken under advisement by the presiding judge. A ruling is expected in March 1997. The Company cannot predict the outcome of this litigation. Pursuant to the terms of the Reorganization, the first $20 million in proceeds, if any, to the Company from this litigation will be distributed to the holders of preferred stock and common stock of the Predecessor Company.

Litigation with Las Cruces

Las Cruces is attempting to replace the Company as its electric service provider by acquiring, through condemnation or otherwise, the distribution assets and other facilities used to provide electric service to customers in Las Cruces. Sales to customers in Las Cruces represented approximately 7% of the Company's operating revenues in 1996. Las Cruces has two actions pending against the Company in federal district court in New Mexico, one seeking to recover franchise fees despite the expiration of the Company's Las Cruces franchise in March 1994 and one seeking a declaratory judgment that Las Cruces can proceed with a condemnation action against the Company. In addition, the New Mexico State Legislature has recently passed a bill that would allow Las Cruces to proceed with the condemnation.

In the franchise fee action, Las Cruces is seeking the reasonable value of the Company's use, occupation and rental of Las Cruces' rights-of-way or damages for trespass and an unspecified amount of punitive damages. The Company has filed an answer denying that it has any liability or continuing payment obligation to Las Cruces regarding franchise fees or use of the Las Cruces rights-of-way, and also denies that it has committed any trespass. The Company intends to vigorously defend the lawsuit. The Company has also filed a counterclaim seeking to condemn, pursuant to statutory authority, those Las Cruces rights-of-way currently used and occupied by the Company. Las Cruces has filed an answer contesting the Company's right to proceed with such a condemnation. In August 1996, the court severed the Company's counterclaim from Las Cruces' claims for all purposes, and stayed all proceedings on the Company's counterclaim until further order of the court. The trial of Las Cruces' claims is set for May 1997. The Company has reserved in its financial statements an amount equal to the franchise fees under the expired agreement.

In April 1995, Las Cruces filed a Complaint for Declaratory Judgment against the Company in the District Court for Dona Ana County, New Mexico, seeking a declaratory judgment that Las Cruces has a right of eminent domain to condemn the electric distribution system and related facilities owned and operated by the Company within and adjacent to the city limits that provide or assist in the provision of electricity within the municipal boundaries of Las Cruces. In May 1995, the Company removed the case to the United States District Court for the District of New Mexico. In October 1995, the Company's motion for summary judgment was denied and the Court ruled that although Las Cruces lacks express statutory authority to condemn the Company's assets, such express authority is required only if the proposed condemnation would materially impair, obliterate or destroy the existing use. Following a trial on the merits, the federal magistrate issued an opinion holding that Las Cruces had not met its burden of proof that its plan would not materially impair the public use of the Company's property sought to be condemned. The magistrate also granted the Company's motion to certify to the New Mexico Supreme Court the question as to whether Las Cruces possesses the authority to condemn the Company's property for use as a municipal utility when that property is already devoted to public use. In February 1997, the New Mexico Supreme Court heard oral arguments and is expected to issue its ruling in the near future.

In March 1997, the New Mexico House of Representatives and Senate passed a bill that would give Las Cruces the authority to acquire and operate the Company's distribution system within both the city limits and a territory within five miles of the municipal boundary. If the Governor signs the bill, it would become law immediately and most likely make the issues presented to the New Mexico Supreme Court moot.

Las Cruces has taken several actions to position itself to acquire portions of the Company's distribution system and certain related facilities in the event it can proceed with condemnation. See Item 1, "Business – Regulation – Federal Regulatory Matters" for discussion regarding Las Cruces' filing with the FERC for determination of stranded cost. In June 1994, the Las Cruces City Council approved a resolution selecting SPS to provide operation and maintenance services for the proposed Las Cruces electric distribution system, substations and associated transmission facilities and authorizing the staff of Las Cruces to negotiate a contract with SPS related to such services. In August 1994, SPS and Las Cruces entered into a fifteen-year contract granting SPS the right to provide all of the electric power and energy required by Las Cruces during the term of the contract. In addition, Las Cruces announced that, in October 1995, it sold approximately $73 million in revenue bonds to provide funding to finance the acquisition by condemnation or negotiated purchase of the Company's electrical distribution assets within and adjacent to the Las Cruces city limits.

The Company has filed a lawsuit in the Dona Ana County District Court and is pursuing a complaint simultaneously before the New Mexico Commission challenging the legality of the sale of the revenue bonds, and the New Mexico Commission is investigating the agreement between SPS and Las Cruces which would grant, in certain circumstances, Las Cruces an option to sell electric utility assets acquired through condemnation to SPS. In August 1996, the Dona Ana County District Court issued an opinion letter stating that Section 3-23-3 of the New Mexico Municipal Code is inapplicable to home rule municipalities and Las Cruces, therefore, was not required to acquire the New Mexico Commission's approval before issuing revenue bonds to acquire utility property. However, the Court did agree with the Company that the revenue bonds, in this case backed by utility revenues, are subject to the same requirements of other revenue bonds backed by gross receipts tax revenues. Therefore, if the Court's finding of the applicability of Las Cruces' home rule authority is overturned on appeal, the Company's position that the issuance of the bonds required prior approval could be upheld. The Court's order was signed and entered in November 1996. The Company has filed an appeal with the New Mexico Court of Appeals.

The Company continues to believe that it can provide lower cost electric service to customers in Las Cruces than can be achieved through a municipal takeover. Accordingly, the Company has stated its strong preference for a resolution of its differences with Las Cruces through negotiation rather than litigation and condemnation. The Company intends to vigorously pursue before the FERC its right to recover stranded costs from Las Cruces in the event Las Cruces succeeds in leaving the system.

If Las Cruces succeeds in its efforts to condemn the Company's distribution system, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court under New Mexico law. "Just compensation" is generally defined as the amount of money that would compensate the party whose property is condemned. In the Company's case, this amount would be the difference between the value of the Company's entire system prior to the taking, as compared to the value of the entire system after the taking. The Company is unable to predict the outcome of Las Cruces' efforts or the effects it may have on the Company's financial position, results of operations and cash flows.

Transmission Service to Mexico

In September 1996, Enron, a wholesale power marketer and one of the companies that submitted a bid to the CFE in connection with renewal of the interchange agreement for the supply of power to Ciudad Juarez, Mexico, filed a complaint against the Company with the FERC. Enron's complaint sought emergency relief and requested the FERC to direct the Company to enter into an agreement with Enron to provide Enron with firm point-to-point transmission service to the CFE under its open access transmission tariff.

In October 1996, the FERC issued an order requiring the Company to provide Enron with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction. Pursuant to an emergency application filed by Enron with the DOE, on October 30, 1996, the DOE issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties in this case. In its response to the DOE's delegation of authority, the Company has asserted that the DOE has no authority to require transmission access for delivery of power to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder in 1997, if the winning bidder is someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position that, under current law, access is not required. The FERC has docketed the Delegation and Assignment and the process is expected to continue throughout 1997.

Water Cases

San Juan River System. The Four Corners Participants are among the defendants in a suit filed by the State of New Mexico in 1975 in state district court in New Mexico against the United States of America, the City of Farmington, New Mexico, the Secretary of the Interior as Trustee for the Navajo Nation and other Indian tribes and certain other defendants (*State of New Mexico ex rel. S. E. Reynolds, New Mexico State*

Engineer v. United States of America, et al., Eleventh Judicial District Court, County of San Juan, State of New Mexico, Cause No. 75-184). The suit seeks adjudication of the water rights of the San Juan River Stream System in New Mexico, which, among other things, supplies the water used at Four Corners. The case has been inactive for many years. The Company cannot predict the outcome of this case.

Gila River System. In connection with the construction and operation of Palo Verde, APS entered into contracts with certain municipalities granting APS the right to purchase effluent for cooling purposes at Palo Verde. In 1986, a summons was served on APS that required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water in an action pending in Maricopa County Superior Court, titled *In re The General Adjudication of All Rights to Use Water in the Gila River System and Source.* Palo Verde is located within the geographic area subject to the summons and the rights of the Palo Verde Participants to the use of groundwater and effluent at Palo Verde is potentially at issue in the action. APS, as operating agent, filed claims that dispute the court's jurisdiction over the Palo Verde Participants' groundwater rights and their contractual rights to effluent relating to Palo Verde and, alternatively, seek confirmation of such rights. In December 1992, the Arizona Supreme Court heard oral argument on certain issues in this matter that are pending on interlocutory appeal. Issues important to Palo Verde Participants' claims were remanded to the trial court for further action and the trial court certified its decision for interlocutory appeal to the Arizona Supreme Court. In September 1994, the Arizona Supreme Court granted review of the June 1994 trial court decision. No trial date has been set in the matter. The Company cannot predict the outcome of this case.

Four Corners

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the "Acts"). In October 1995, the Four Corners Participants requested that the United States Secretary of the Interior resolve their dispute with the Navajo Nation regarding whether the Acts apply to operation of Four Corners. The Four Corners Participants subsequently filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that (i) the Four Corners leases and federal easements preclude the application of the Acts to the operation of Four Corners; and (ii) the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners. On October 18, 1995, the Navajo Nation and the Four Corners Participants agreed to indefinitely stay the proceedings referenced above so that the parties may attempt to resolve the dispute without litigation. The Company is unable to predict the outcome of this matter.

Other Legal Proceedings

The Company is a party to various other claims, legal actions and complaints. In many of these matters, the Company has excess casualty liability insurance which is applicable. Based upon a review of these claims and applicable insurance coverage, management is of the opinion that none of these claims will have a material adverse effect on the operations or financial position of the Company.

Item 4. Submission of Matters to a Vote of Security Holders

On November 14, 1996, the Company held a Special Shareholders Meeting to approve the Company's 1996 Long-Term Incentive Plan, which authorized the issuance of up to 3,500,000 shares of common stock for the benefit of officers, key employees and non-employee directors through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock and performance stock. The total number of common shares outstanding at this Special Meeting was 59,999,981, of which 46,078,152 were represented in person or by proxy. Shares voted in favor of approving the plan were 38,325,050, and shares voted against were 7,308,727. There were 444,375 abstentions. Broker non-votes were not included in the determination of the number of shares represented at the meeting for purposes of determining whether a quorum was present and were not counted for purposes of determining whether the proposal had been approved. See Part II, Item 8, "Financial Statements and Supplementary Data – Note F of Notes to Financial Statements."

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Company's Common Stock began trading on the American Stock Exchange on February 16, 1996 under the symbol "EE." The high and low sales prices for the Company's Common Stock, as reported in the consolidated reporting system of the American Stock Exchange, for the periods indicated below, were as follows:

	Sales Price	
	High	Low
1996		
February 16 - March 31	$ 6 1/4	$ 4 3/4
Second Quarter	6 1/8	5
Third Quarter	6 1/8	5 1/4
Fourth Quarter	6 5/8	4 15/16

At March 20, 1997, there were 11,847 record holders of the Company's Common Stock.

The Company's ability to pay dividends on the Common Stock for the next several years will be limited by applicable law and, as explained below, by the financing arrangements entered into pursuant to the Reorganization. All distributions with respect to the Common Stock, including the declaration or payment of dividends, are subject to the provisions of the Texas Business Corporation Act, including provisions that prohibit any distribution that exceeds the surplus of the Company. In addition, under Section 305 of the FPA, it is unlawful for a director or officer of the Company to participate in the making or payment of dividends from "any funds properly included in capital account." As a result of Reorganization, the Company's first priority at this time is debt retirement and deleveraging as opposed to paying dividends.

Pursuant to the resolutions creating the Company's Series A Preferred Stock, no dividends can be paid on the Common Stock if there are dividends in arrears on the Series A Preferred Stock. So long as the Company's First Mortgage Bonds, Series A through H, are outstanding and the series with the longest maturity is not rated "investment grade" by either Standard & Poor's Rating Service or Moody's Investors Service, Inc., the Company may not declare any dividend on the Common Stock, other than in additional shares of Common Stock, or make any other distribution on, or acquire for value any shares of Common Stock (with certain limited exceptions) unless, after giving effect thereto, the aggregate of all such dividends, distributions and certain other payments made by the Company since February 12, 1996 would be less than the sum of (i) 50% of the consolidated net income (as defined in the mortgage indenture) of the Company minus dividends paid in respect of the Series A Preferred Stock for the period from February 13, 1996 to the most recently ended fiscal quarter for which quarterly financial statements are available (or, if such consolidated net income is a deficit, less 100% of such deficit), plus (ii) 100% of the aggregate net proceeds received by the Company from the issuance or sale since February 12, 1996 of equity securities or debt securities that have been converted into equity securities, plus (iii) $10.0 million. Currently, the Company's First Mortgage Bonds are not rated investment grade.

Pursuant to the terms of the reimbursement agreements related to four letters of credit issued in respect to the four series of pollution control revenue bonds, so long as a drawing is available under any of the letters of credit, the same limitation on the declaration of dividends would apply to the Company. In addition to the restriction contained in the mortgage indenture, the reimbursement agreements limit to $15.0 million the aggregate amount of dividends that can be paid on the Common Stock during the three years after its initial issuance on February 12, 1996. The credit agreement for the working capital and fuel financing facility contains the same limitations on the payment of Common Stock dividends as the reimbursement agreements related to the letters of credit on the pollution control revenue bonds.

Item 6. Selected Financial Data

As of and for the following periods:

	Reorganized Company	Predecessor Company				
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994	1993	1992
		(In thousands except for share data)				
Operating revenues	$ 523,974	$ 54,919	$ 504,617	$ 536,760	$ 543,594	$ 524,760
Operating income	120,787	5,089	66,146	73,011	64,971	67,036
Income (loss) before extraordinary gain on discharge of debt and cumulative effect of a change in accounting principle	41,919	118,198	(33,319)	(28,153)	(41,855)	(28,180)
Extraordinary gain on discharge of debt	-	264,273	-	-	-	-
Cumulative effect of a change in accounting principle	-	-	-	-	(96,044)(1)	-
Net income (loss) applicable to common stock	31,431	382,471	(33,319)	(28,153)	(137,899)	(28,180)
Net income (loss) per common share:						
Income (loss) before extraordinary gain on discharge of debt and cumulative effect of a change in accounting principle	0.52	3.33	(0.94)	(0.79)	(1.18)	(0.79)
Extraordinary gain on discharge of debt	-	7.43	-	-	-	-
Cumulative effect of a change in accounting principle	-	-	-	-	(2.70)(1)	-
Net income (loss) per common share	0.52	10.76	(0.94)	(0.79)	(3.88)	(0.79)
Weighted average number of common shares and common share equivalents outstanding	60,181,494	35,544,330	35,544,330	35,544,330	35,539,480	35,530,264
Total assets	1,846,190	1,910,354	1,809,891	1,730,851	1,715,406	1,702,778
Additions to utility plant	53,018	8,231	88,267	60,113	58,215	60,570
Long-term debt, financing and capital lease obligations	1,046,173	1,164,328	-	-	-	-
Debt and obligations subject to compromise	-	-	1,608,091	1,537,303	1,495,315	1,440,968
Preferred stock	108,426	100,000	81,464	81,464	81,464	81,464
Common stock equity (deficit)	331,257	300,000	(418,763)	(385,966)	(357,463)	(220,508)

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(1) Reflects the change in accounting for income taxes due to the implementation of SFAS No. 109, "Accounting for Income Taxes" ("SFAS No. 109").

The selected financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data," below.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Statements in this document, other than statements of historical information, are forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (the "1995 Act"). Such forward-looking statements, as well as other oral and written forward-looking statements made by or on behalf of the Company from time to time, including statements contained in the Company's filings with the Securities and Exchange Commission and its reports to stockholders, involve known and unknown risks and other factors which may cause the Company's actual results in future periods to differ materially from those expressed in any forward-looking statements. Any such statement is qualified by reference to the risks and factors discussed below under the headings "Operational Prospects and Challenges" and "Liquidity and Capital Resources" and in the Company's filings with the Securities and Exchange Commission, which are available from the Securities and Exchange Commission or which may be obtained upon request from the Company. The Company cautions that the foregoing list of important factors is not exclusive. The Company does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of the Company.

Operational Prospects and Challenges

While the Company prepares for a new era of deregulation and competition in the electric utility industry, the Rate Stipulation provides a certain level of stability in the rates that the Company currently charges the majority of its customers. The Company intends to enhance its position during the Freeze Period by (i) serving the growing need for electricity within its retail service territory; (ii) continuing to focus on its strategic location on the border with Mexico; (iii) executing long-term contracts to provide electricity to its largest retail customers; and (iv) implementing operating cost reduction programs.

The Company faces a number of challenges which could negatively impact its operations during the Freeze Period. The primary challenge is the risk of increased costs, including the risk of additional or unanticipated costs, at Palo Verde resulting from (i) increases in operation and maintenance expenses; (ii) the potential replacement of steam generators; (iii) an extended outage of any of the Palo Verde units; (iv) increases in estimates of decommissioning costs; (v) the storage of radioactive materials; and (vi) compliance with the various requirements and regulations governing commercial nuclear generating stations. There can be no assurance that the Company's revenues will be sufficient to recover any increased costs incurred during the Freeze Period, including any such increased costs in connection with Palo Verde or increases in other costs of operation, whether as a result of higher than anticipated levels of inflation, changes in tax laws or regulatory requirements, or other causes.

In recent months, rapid escalation in fuel prices have increased concern over price levels for energy, including electricity. The Company's recovery of fuel expense is subject to challenges regarding reasonableness and prudence through periodic fuel reconciliation proceedings. See Part I, Item 1, "Business – Regulation – Texas Rate Matters – Fuel" and "– Regulation – New Mexico Rate Matters – Fuel."

Another risk to the Company's operations is the potential loss of customers. The Company's wholesale and large retail customers currently have, in varying degrees, and, in the future may have, additional alternate sources of economical power, including co-generation of electric power. If the Company loses a significant portion of its retail customer base or wholesale sales, the Company may not be able to replace such revenues through either the addition of new customers or an increase in rates to remaining customers. Las Cruces has begun litigation and the New Mexico State Legislature has passed legislation which, if signed by the Governor, would give Las Cruces the legal authority to condemn the Company's distribution system and related assets located within its city limits. If Las Cruces succeeds in its efforts, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court. See Item 8, "Financial Statements and Supplementary Data – Note K of Notes to Financial Statements." Further, there are state and federal legislative initiatives related to deregulation which could affect Company operations.

In recent years, the United States has closed a large number of military bases and there can be no assurance that Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") or the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss") will not be closed in the future or that the Company will not lose all or some of its military base sales. The Company's sales to the military bases represented approximately \$20.0 million or 3% of operating revenues for the year ended December 31, 1996. The Company signed a new contract with Ft. Bliss in August 1996, which provides that Ft. Bliss will take service from the Company through 1999, with the right thereafter to continue service on a year to year basis for two years. The Company has a contract for service to Holloman for a ten-year term beginning in December 1995. In August 1996, the Army advised the Company that White Sands would continue to purchase retail electric service from the Company pursuant to the retail service contract which was set to expire on December 31, 1993, but which had previously been unilaterally extended by the Army for an indefinite period, until written termination of such contract by the Army not less than one year in advance of the termination date.

The Company does not currently have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation. Pursuant to an order from the New Mexico Commission, the Company filed rate data with the Commission on March 3, 1997. Although the Company's filing demonstrates a revenue deficiency of approximately \$8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Finally, the electric utility industry in general is facing significant challenges and increased competition as a result of changes in federal provisions relating to third-party transmission services and independent power production, as well as potential changes in state regulatory provisions relating to wholesale and retail service. Both the Texas and New Mexico Commissions are conducting proceedings related to industry restructuring and stranded cost recovery. See Part I, Item 1, "Business – Regulation – Recent Changes in Utility Regulation." The Company cannot predict the outcome of these proceedings. The potential effects of deregulation are particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flow and financial condition of the Company.

Liquidity and Capital Resources

The Company's principal liquidity requirements through the end of the decade are expected to consist of the payment of interest on the Company's indebtedness and capital expenditures related to the Company's generating facilities and transmission and distribution systems. The Company expects that cash flows from operations will be sufficient for such purposes.

Long-term capital requirements of the Company will consist primarily of maintenance and construction of electric utility plant, payment of interest on and retirement of debt and payment of dividends on and redemption of preferred stock. The Company has no current plans to construct any new generating capacity through at least 2004. Utility construction expenditures will consist primarily of expanding and updating the transmission and distribution systems and the cost of betterments and improvements to Palo Verde and other generating facilities.

The Company anticipates that internally generated funds will be sufficient to meet its construction requirements, provide for the retirement of debt at maturity and enable the Company to meet other contingencies that may exist, such as compliance with environmental regulation, pending litigation and any claims for indemnification. At December 31, 1996, the Company had approximately $68.8 million in cash and cash equivalents, out of which approximately $9.1 million of reorganization expenses are expected to be paid upon receipt of the Bankruptcy Court's final order for allowable professional fees related to the Company's bankruptcy proceedings. The Company also has a $100 million revolving credit facility, which provides up to $60 million for nuclear fuel purchases and up to $50 million (depending on the amount of borrowings outstanding for nuclear fuel purchases) for working capital needs. At December 31, 1996, approximately $46.6 million had been drawn for nuclear fuel purchases. No amounts have been drawn on this facility for working capital needs.

The Company has substantial leverage and significant debt service obligations and, primarily due to the Rate Stipulation, does not expect to be able to raise its base rates in order to recover any future increases in non-fuel costs or to replace any lost revenues. As of December 31, 1996, the Company had total long-term indebtedness, including the long-term portion of financing and capital lease obligations, of approximately $1,046 million and redeemable preferred stock of $108 million. Long-term indebtedness as a percentage of total capitalization totaled approximately 70%.

From June 1996 through March 20, 1997, the Company repurchased approximately $168 million of its first mortgage bonds, which repurchases, net of related issuance cost, did not result in a material net gain or loss. From time to time, based on prevailing market conditions, the Company intends to continue to use a portion of its available cash flow to reduce fixed obligations by making open market purchases of first mortgage bonds.

The degree to which the Company is leveraged could have important consequences on the Company's liquidity, including (i) the Company's ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes could be limited in the future; (ii) a substantial portion of the Company's cash flow from operations will be dedicated to the payment of principal and interest on its indebtedness, thereby reducing the funds available to the Company for other purposes; and (iii) the Company's substantial leverage may place the Company at a competitive disadvantage, hinder its ability to adjust rapidly to changing market conditions and make it more vulnerable in the event of a downturn in general economic conditions or its business. As a result, any significant reduction in revenues and/or significant increase in costs or expenditures could adversely affect the Company's liquidity.

Historical Results of Operations

General

The Company derives revenue principally from the sale of power to retail and wholesale customers, which accounted for 80.8% and 18.5%, respectively, of the Reorganized and Predecessor Companies' combined revenues for the year ended December 31, 1996, and 79.6% and 19.7%, respectively, of the Predecessor Company's revenues for the year ended December 31, 1995. Revenues from the sale of electricity include fuel revenues based upon fuel costs, which are generally passed through directly to customers, and base revenues. Base revenues refers to the Company's revenues from the sale of electricity excluding such fuel revenues.

The Company's retail customers consist of residential customers, small commercial and industrial customers, large commercial and industrial customers and public authorities, which accounted for 36%, 36%, 11% and 17%, respectively, of the Company's retail base revenues for the year ended December 31, 1996 and 36%, 36%, 11% and 17%, respectively, of the Company's retail base revenues for the year ended December 31, 1995. Wholesale revenues consist of sales pursuant to long-term power contracts, sales to CFE, and spot market sales, which accounted for 51%, 36% and 13%, respectively, of the Company's wholesale base revenues for the year ended December 31, 1996 and 56%, 36% and 8%, respectively, of the Company's wholesale base revenues for the year ended December 31, 1995. Sales to the Company's largest wholesale customer, IID, accounted for 7.5% and 8.8% of the Company's base revenues for the years ended December 31, 1996 and 1995, respectively. No retail customer accounted for more than 3% of the Company's base revenues during such periods.

The Company's business is seasonal, with higher revenues generated during the summer season. The following table sets forth the percentage of the Company's revenues derived during each quarter of the periods presented.

	Years Ended December 31,		
	1996	1995	1994
First Quarter	21%	22%	23%
Second Quarter	25	25	26
Third Quarter	29	29	29
Fourth Quarter	25	24	22
Total	100%	100%	100%

Palo Verde, which provides approximately 40% of the Company's available net generating capacity and provided approximately 53% of the Company's available energy for the year ended December 31, 1996, is subject to performance standards in New Mexico and Texas. If such performance standards are not met, the Company is subject to a penalty. If standards are exceeded, the Company is entitled to a reward. See Part I, Item 1, "Business – Regulation – New Mexico Rate Matters – Palo Verde Performance Standards" and "– Regulation – Texas Rate Matters – Palo Verde Performance Standards."

Year Ended December 31, 1996 Compared to Year Ended December 31, 1995

Operating Revenues

Combined operating revenues for the Reorganized Company and Predecessor Company increased 14.7% to $578.9 million in 1996 compared to $504.6 million in 1995 primarily due to (i) increased base revenues and (ii) increased fuel revenues. The Company achieved record total system peak demand of 1,387 MW in 1996, representing a 0.9% increase over 1995's record peak of 1,374 MW.

Base Revenues. Combined base revenues increased 6.7% to $460.9 million in 1996 compared to $432.0 million in 1995, primarily due to an increase in Texas base rates associated with the implementation of the Rate Stipulation and an increase in KWH sales.

KWH sales increased 4.9% in 1996 compared to 1995 primarily due to (i) warm weather and (ii) a 1.9% increase in the average number of customers served.

	KWH Sales		Increase
	1996	1995	(Decrease)
	(In thousands)		
Retail	5,652,907	5,416,902	4.4%
Wholesale	1,753,553	1,646,357	6.5%
Total	7,406,460	7,063,259	4.9%

Fuel Revenues and Economy Sales. Regulations of the Texas and New Mexico Commissions allow substantially all fuel and purchased and interchanged power costs to be passed through directly to customers. These costs are reflected in the Company's fuel revenues. Combined fuel revenues and economy sales increased 65.7% to $114.0 million in 1996 compared to $68.8 million in 1995 primarily due to (i) increased fuel and purchased and interchanged power costs; (ii) increased economy energy sales; and (iii) changes in the Texas fuel revenue calculation associated with the implementation of the Rate Stipulation.

Fuel and Purchased and Interchanged Power Expense

Combined fuel and purchased and interchanged power expense (substantially all of which is expected to be recovered by the Company in fuel revenues as described above) increased 33.0% to $123.1 million in 1996 compared to $92.6 million in 1995. Such increase was primarily due to increased cost of natural gas and volume of fuel used in Company-owned generation and to increased volume of higher cost purchased power resulting from (i) increased KWH sales in 1996 and (ii) the timing and duration of maintenance outages at Company-owned plants, and refueling outages at Palo Verde in 1996 compared to 1995.

Other Operation and Maintenance Expense

Combined other operation and maintenance expense decreased 29.0% to $178.7 million in 1996 compared to $251.9 million in 1995 due to decreased Palo Verde costs of approximately $72.0 million. The reduction in Palo Verde costs consisted of approximately $67.3 million associated with lease accruals recorded in 1995, with no corresponding accrual in 1996 by the Reorganized Company as a result of the reacquisition of the leased portion of Palo Verde in the Reorganization, and approximately $4.7 million primarily from the timing and duration of unit refuelings during the periods.

Depreciation and Amortization Expense

Combined depreciation expense increased $29.6 million to $86.3 million in 1996 compared to $56.8 million in 1995. The effect of an increase in depreciable plant following the reacquisition in the Reorganization of a portion of Palo Verde was partially offset by the decrease in the book value of depreciable plant from fresh-start adjustments. The effect of the implementation of fresh-start reporting and the accelerated depreciation of a portion of such amounts over the period of the Rate Stipulation resulted in increased depreciation expense of $37.2 million for the period February 12, 1996 to December 31, 1996 partially offset by decreased nuclear decommissioning amortization. As part of the adoption of fresh-start reporting, the Company recognized the net present value of estimated future expenditures for nuclear decommissioning of approximately $84.9 million.

Federal Income Taxes

Combined federal income tax expense, excluding the deferred income tax effects of fresh-start reporting, reorganization items and income taxes on interest income during bankruptcy, increased $29.8 million to $19.0 million in 1996 compared to a tax benefit of $10.8 million in 1995 primarily due to changes in pretax income and certain differences in book and taxable income.

State Income Taxes

Combined state income tax expense, excluding deferred income taxes recognized in reorganization items, increased $9.3 million to $4.3 million in 1996 compared to a state tax benefit of $5.0 million in 1995 primarily due to changes in pretax income and certain differences in book and taxable income.

Other Taxes

Combined taxes other than income taxes decreased $9.0 million to $44.6 million in 1996 compared to $53.6 million in 1995 primarily due to (i) a decrease in Arizona property tax resulting from a new state property tax law which reduced the property taxes for 1996; (ii) a decrease in taxable property base resulting from depreciation; and (iii) the elimination of Arizona sales tax on lease payments due to reacquisition of leased property in February 1996. The decrease was partially offset by an increase in revenue related tax. Under the recently enacted law in Arizona, the Company's property taxes were approximately $17.1 million for 1996, a reduction of approximately $8.8 million from 1995.

Gain on Sale of Investment

In August 1996, the Company's warrant to buy up to 49.75% of the equity interest in CAI Corporation was sold for $20.2 million. The sale resulted in a pretax gain of $3.8 million based on a book value of $16.4 million.

Investment Income

Combined investment income on cash for the Reorganized Company is classified as Other Income, whereas investment income on cash for the Predecessor Company is included in Reorganization Items (Expense). Combined investment income decreased 52.7% to $6.3 million in 1996 compared to $13.2 million in 1995 due to reduced levels of cash resulting from repurchases of debt and the payment of bankruptcy related claims pursuant to the Plan.

Settlement of Bankruptcy Professional Fees

The Company recorded a change in estimate of approximately $2.3 million related to accrued professional fees as a result of Bankruptcy Court proceedings.

Interest Charges

Combined interest charges increased 8.1% to $95.3 million in 1996 compared to $88.1 million in 1995 primarily due to (i) increased interest on mortgage bonds due to a greater amount of bonds being outstanding subsequent to the Reorganization, and (ii) accretion of the nuclear decommissioning liability as a result of implementing fresh-start reporting. This increase was partially offset by decreased interest charges due to the extinguishment of certain debt in conjunction with the Reorganization.

Reorganization Items

Reorganization items for the Predecessor Company for the period January 1, 1996 to February 11, 1996 was a benefit of $122.2 million compared to an expense of $10.0 million for the twelve months ended December 31, 1995. The benefits recorded by the Predecessor Company upon the emergence from bankruptcy consisted of deferred income tax benefits related to the Reorganization and the effects of the Rate Stipulation. These benefits were offset by (i) the adjustments of assets and liabilities to their fair market values; (ii) provisions for settlement of claims; and (iii) professional fees and other expenses. The reorganization expense recorded in 1995 consisted of professional fees partially offset by interest earned on accumulated cash resulting from the Bankruptcy Case. See Note B of Notes to Financial Statements.

Extraordinary Gain on Discharge of Debt

Extraordinary gain on discharge of debt for the Predecessor Company for the period January 1, 1996 to February 11, 1996 consisted of forgiveness of indebtedness primarily related to the extinguishment of Palo Verde lease obligations.

Net Income

The combined change in 1996 net income was primarily due to the extraordinary gain on discharge of debt and reorganization items related to the Company's emergence from bankruptcy, with no comparable activity in 1995.

Year Ended December 31, 1995 Compared to Year Ended December 31, 1994

Operating Revenues

Operating revenues decreased 6.0% to $504.6 million in 1995 compared to $536.8 million in 1994 primarily due to a decrease in fuel revenues. Nonetheless, the Company achieved a then record total system peak demand of 1,374 MW in 1995, representing a 0.7% increase over 1994's record peak of 1,365 MW.

Base Revenues. Base revenues remained relatively unchanged at $432.0 million in 1995 compared to $431.6 million in 1994.

Total system firm energy sales decreased to 7,063,259 MWH in 1995 from 7,321,711 in 1994. Retail firm energy sales increased 20,862 MWH over the same time period.

In July 1994, the Company implemented an increase in base rates for Texas retail customers subject to refund and bond. Accordingly, the Company deferred recognition of those revenues, which are not included in either 1995 or 1994 results. Revenues deferred for 1995 and 1994 were $24.1 million and $11.5 million, respectively, and total revenues subject to refund aggregated $35.6 million at December 31, 1995.

Fuel Revenues. Regulations of the Texas and New Mexico Commissions allow substantially all changes in fuel and purchased and interchanged power costs to be passed through directly to customers. These costs are reflected in the Company's revenues. Fuel revenues decreased 31.9% to $68.8 million in 1995 compared to $101.1 million in 1994 primarily due to reduced cost of fuel for Company-owned generation and changes in generation supply from higher cost purchased power to Company-owned generation. During the fourth quarter of 1995, the Company reserved $2.3 million against fuel revenues to reflect additional fuel and purchased and interchanged power costs incurred related to operating conditions during the initial remediation following the system outages.

If the provisions of the Rate Stipulation concerning fuel issues had been implemented for 1995, fuel revenues would have been $16.3 million greater. Under the Agreed Order, the Company retained fuel revenues in the amount of $46.1 million that had been accrued as a provision for refund in the financial statements.

Fuel and Purchased and Interchanged Power Expense

Fuel and purchased and interchanged power expense decreased 22.7% to $92.6 million in 1995 compared to $119.8 million in 1994. Such decrease was primarily attributable to the reduced cost of fuel for Company-owned generation and changes in the fuel mix from higher cost purchased power to nuclear fuel.

Other Operation and Maintenance Expense

Other operation and maintenance expense decreased 0.8% to $251.9 million in 1995 compared to $253.8 million in 1994 as a result of (i) decreased Palo Verde costs of $3.7 million; (ii) decreased rents of $1.2 million primarily related to lease expenses for the Company's computer system; (iii) decreased general maintenance costs at a Company-operated generation plant of $1.0 million; (iv) decreased pension and benefit costs of $0.9 million primarily due to a change in actuarial assumptions; and (v) decreased transmission costs of $0.8 million primarily related to the installation of transmission equipment which eliminated fees for transmission services. Such decreases were partially offset by (i) increased outside service costs of $3.3 million primarily related to condemnation and franchise issues for Las Cruces; and (ii) increased maintenance costs of $2.2 million at a Company-operated generating plant.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $2.9 million to $56.8 million in 1995 compared to $53.8 million in 1994 primarily due to increases in depreciable plant balances and a $0.6 million inflation adjustment to the DOE's assessment on Palo Verde related to a Decontamination and Decommissioning Fund established by the Energy Policy Act.

Federal Income Taxes

Federal income tax benefits decreased $9.5 million to $7.3 million in 1995 compared to $16.8 million in 1994 primarily due to changes in pretax income and differences in book and taxable income.

State Income Tax

State income tax expense decreased $5.2 million to a tax benefit of $5.0 million in 1995 compared to $0.2 million expense in 1994 primarily due to a decrease in pretax income and certain differences in book and taxable income.

Other Taxes

Taxes other than income taxes decreased $0.7 million to $53.6 million in 1995 compared to $54.3 million in 1994 due to a decrease in property taxes resulting from a decrease in taxable base and a decrease in Arizona sales tax resulting from an accrual in 1994 for prior years' taxes with no corresponding accrual in 1995.

Other Income, Net

Other income, net decreased $4.3 million to a net deduction of $0.9 million in 1995 compared to other income, net of $3.4 million in 1994 primarily due to (i) a gain of $2.4 million on the sale of the Company's interest in Triangle Electric Supply Company in 1994 with no comparable gain in 1995; and (ii) the recording of $0.9 million of expense in 1995 compared to $0.5 million of income in 1994 related to Company-owned life insurance policies.

Interest Charges

Interest charges decreased $6.9 million to $88.1 million in 1995 compared to $95.0 million in 1994 primarily due to the Company's discontinuance of interest accruals on unsecured debt pursuant to Bankruptcy Court order which was offset partially by increased interest rates on interim payments to certain secured and unsecured creditors.

Reorganization Items

Reorganization items expense increased 11.0% to $10.0 million in 1995 compared to $9.0 million in 1994. Such increase of reorganization items expense was due to increased professional fees and other costs in 1995 partially offset by increased interest earned on accumulated cash in 1995 due to higher cash balances and investment interest rates.

Net Loss

Net loss increased $5.2 million to $33.3 million in 1995 compared to $28.2 million in 1994. The principal factors giving rise to the loss in 1995 were (i) that revenues were not sufficient to recover fully the Company's costs of service and debt service; and (ii) reorganization expenses.

Effects of Inflation

Over the recent past, inflation has been relatively low. As such, its impact to the Company's results of operations and financial condition has not been significant.

Effect of Recently Issued Accounting Standards

SFAS No. 128, "Earnings per Share" ("SFAS No. 128"), establishes standards for computing and presenting earnings per share and applies to entities with publicly held common stock. The effective date of SFAS No. 128 is for financial statements issued for periods ending after December 15, 1997, including interim periods; earlier application is not permitted. The Company has not performed an analysis to determine what effect, if any, SFAS No. 128 will have on its financial statements.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

The Shareholders and Board of Directors
El Paso Electric Company

We have audited the accompanying balance sheets of El Paso Electric Company (the "Company") as of December 31, 1996 and 1995 and the related statements of operations, accumulated earnings (deficit), and cash flows for the period February 12, 1996 to December 31, 1996, the period January 1, 1996 to February 11, 1996 and for each of the years in the two-year period ended December 31, 1995. 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 generally accepted auditing standards. 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 El Paso Electric Company as of December 31, 1996 and 1995, and the results of its operations and its cash flows for the period February 12, 1996 to December 31, 1996, the period January 1, 1996 to February 11, 1996 and for each of the years in the two-year period ended December 31, 1995 in conformity with generally accepted accounting principles.

As discussed in Notes A and B of Notes to Financial Statements, on February 12, 1996, the Company emerged from bankruptcy. The financial statements of the reorganized Company reflect assets at reorganization value and liabilities at fair value under fresh-start reporting. As a result, the financial statements of the reorganized Company are presented on a different basis than those prior to the reorganization and, therefore, are not comparable in all respects.

KPMG Peat Marwick LLP

El Paso, Texas
March 27, 1997

EL PASO ELECTRIC COMPANY
BALANCE SHEETS

ASSETS (In thousands)	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Utility plant (Notes A, C, D, E and H):		
Electric plant in service	$ 1,492,737	$ 1,744,468
Less accumulated depreciation and amortization	77,976	465,311
Net plant in service	1,414,761	1,279,157
Construction work in progress	44,432	61,274
Nuclear fuel; includes fuel in process of $5,084 and $6,071, respectively	60,014	82,904
Less accumulated amortization	18,651	43,599
Net nuclear fuel	41,363	39,305
Net utility plant	1,500,556	1,379,736
Current assets:		
Cash and temporary investments	68,767	262,507
Accounts receivable, principally trade, net of allowance for doubtful accounts of $6,161 and $6,031, respectively	57,587	59,233
Federal income tax receivable	20,713	–
Inventories, at cost	28,322	32,737
Prepayments and other	10,652	8,877
Total current assets	186,041	363,354
Long-term contract receivable (Note C)	31,057	33,683
Deferred charges and other assets:		
Accumulated deferred income taxes, net (Note I)	73,884	–
Decommissioning trust fund (Note E)	33,054	26,183
Other	21,598	6,935
Total deferred charges and other assets	128,536	33,118
Total assets	$ 1,846,190	$ 1,809,891

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands except for share data)	Reorganized Company December31, 1996	Predecessor Company December31, 1995
Capitalization (Notes A, F and G):		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 59,999,981 shares issued and outstanding; and 180,000 restricted shares as of December 31, 1996	$ 60,180	$ –
Capital in excess of stated value	240,768	–
Unearned compensation – restricted stock awards	(758)	–
Predecessor common stock, no par value, 100,000,000 shares authorized, 35,544,330 shares issued and outstanding as of December 31, 1995	–	339,097
Accumulated earnings (deficit)	30,835	(758,032)
Net unrealized gain on marketable securities, less applicable income tax expense of $125 and $93, respectively	232	172
Common stock equity (deficit)	331,257	(418,763)
Preferred stock, cumulative, no par value, 2,000,000 shares authorized,, Redemption required – 1,084,264 shares issued and outstanding; at liquidation preference	108,426	–
Long-term debt (Note H)	1,021,749	–
Financing and capital lease obligations (Note H)	24,424	–
Predecessor preferred stock, cumulative, no par value, 2,000,000 shares authorized:		
Redemption required	–	67,266
Redemption not required	–	14,198
Obligations subject to compromise	–	1,608,091
Total capitalization	1,485,856	1,270,792
Current liabilities:		
Current maturities of financing and capital lease obligations (Note H)	28,333	–
Accounts payable, principally trade	37,215	34,900
Taxes accrued other than federal income taxes	21,296	24,629
Interest accrued	23,150	–
Net overcollection of fuel revenues (Note C)	–	53,788
Revenues subject to refund (Note C)	–	35,582
Other	15,000	14,266
Total current liabilities	124,994	163,165
Deferred credits and other liabilities:		
Decommissioning (Note E)	89,544	47,245
Accrued postretirement benefit liability (Note L)	71,313	20,298
Accrued pension liability (Note L)	34,550	14,163
Other	39,933	17,465
Accumulated deferred income taxes (Note I)	–	70,010
Accumulated deferred investment tax credits (Note I)	–	78,275
Deferred gain on sales and leasebacks	–	128,478
Total deferred credits and other liabilities	235,340	375,934
Commitments and contingencies (Notes A, B, C, E, J, K and L)		
Total capitalization and liabilities	$ 1,846,190	$ 1,809,891

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
(In thousands except for share data)

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	Years Ended December 31, 1994
Operating revenues:				
Base revenues	$ 416,221	$ 44,679	$ 432,050	$ 431,634
Fuel revenues and economy sales	104,193	9,849	68,823	101,076
Other	3,560	421	3,744	4,050
	523,974	54,949	504,617	536,760
Operating expenses:				
Operation:				
Fuel	92,899	10,125	76,005	89,893
Purchased and interchanged power	17,821	2,282	16,568	29,929
	110,720	12,407	92,573	119,822
Other	115,742	23,559	208,445	209,814
Maintenance	34,702	4,743	43,412	44,022
Depreciation and amortization	79,772	6,577	56,762	53,841
Taxes:				
Federal income tax expense (benefit) (Note I)	18,659	(2,700)	(11,248)	(18,234)
State income tax expense (benefit) (Note I)	5,045	(750)	(5,024)	220
Other	38,547	6,024	53,551	54,264
	403,187	49,860	438,471	463,749
Operating income	120,787	5,089	66,146	73,011
Other income (deductions):				
Investment income	4,796	–	–	–
Gain on sale of investment	3,844	–	–	–
Settlement of bankruptcy professional fees	2,305	–	–	–
Other, net	(681)	50	(910)	3,378
Federal income tax expense applicable to other income (Note I)	(2,966)	(35)	(474)	(516)
	7,298	15	(1,384)	2,862
Income before interest charges	128,085	5,104	64,762	75,873
Interest charges (credits):				
Interest on long-term debt	85,633	–	–	–
Other interest	5,722	–	–	–
Interest during reorganization	–	9,569	91,923	97,616
Interest capitalized and deferred	(5,189)	(412)	(3,820)	(2,581)
	86,166	9,157	88,103	95,035
Income (loss) before reorganization items (expense) and extraordinary gain on discharge of debt	41,919	(4,053)	(23,341)	(19,162)
Reorganization items (expense), net of income tax benefit (expense) (Note B)	–	122,251	(9,978)	(8,991)
Income (loss) before extraordinary gain on discharge of debt	41,919	118,198	(33,319)	(28,153)
Extraordinary gain on discharge of debt (Note B)	–	264,273	–	–
Net income (loss)	41,919	382,471	(33,319)	(28,153)
Preferred stock dividend requirements	10,488	–	–	–
Net income (loss) applicable to common stock	$ 31,431	$ 382,471	$ (33,319)	$ (28,153)
Net income (loss) per common share (Note D):				
Income (loss) before extraordinary gain on discharge of debt	$ 0.52	$ 3.33	$ (0.94)	$ (0.79)
Extraordinary gain on discharge of debt	–	7.43	–	–
Net income (loss)	$ 0.52	$ 10.76	$ (0.94)	$ (0.79)

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF ACCUMULATED EARNINGS (DEFICIT)
(In thousands except for share data)

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Accumulated earnings (deficit) at beginning of period	$ –	$ (758,032)	$ (724,713)	$ (696,560)
Add:				
Net income (loss)	41,919	382,471	(33,319)	(28,153)
Elimination of predecessor equity accounts (Note A)	–	375,561	–	–
	41,919	758,032	(33,319)	(28,153)
Deduct:				
Cumulative preferred stock dividend requirement	10,488	–	–	–
Capital stock expense	596	–	–	–
	11,084	–	–	–
Accumulated earnings (deficit) at end of period	$ 30,835	$ –	$ (758,032)	$ (724,713)
Weighted average number of common shares and common share equivalents outstanding	60,181,494	35,544,330	35,544,330	35,544,330

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(In thousands)

	Reorganized Company Period From February 12 to December 31, 1996	Predecessor Company Period From January 1 to February 11, 1996	Predecessor Company Years Ended December 31, 1995	Predecessor Company Years Ended December 31, 1994
Cash Flows From Operating Activities:				
Net income (loss)	$ 41,919	$ 382,471	$ (33,319)	$ (28,153)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization	99,355	8,246	69,444	67,189
Deferred income taxes and investment tax credit, net	41,341	(3,116)	(26,744)	(17,990)
Reorganization items, net of income tax benefit	–	(122,251)	–	–
Extraordinary gain on discharge of debt	–	(264,273)	–	–
Gain on sale of investment	(3,844)	–	–	–
Other operating activities	562	(805)	(6,795)	(5,429)
Change in:				
Accounts receivable	3,513	5,429	(4,866)	285
Federal income tax receivable	(20,713)	–	–	–
Inventories	(32)	90	1,590	268
Prepayments and other	(1,974)	34	2,214	(1,056)
Long-term contract receivable	2,333	293	(80)	(1,183)
Obligations subject to compromise	–	9,430	71,839	42,943
Accounts payable	(4,038)	(6,859)	11,885	(14,017)
Interest accrued	23,034	–	–	–
Net overcollection of fuel revenues	(10,784)	417	16,581	23,333
Revenues subject to refund	–	2,785	24,107	11,475
Other current liabilities	(1,242)	(152)	1,027	1,897
Deferred charges and credits	(1,117)	1,994	21,187	13,885
Net cash provided by operating activities	168,313	13,733	148,070	93,447
Cash Flows From Investing Activities (Note B):				
Additions to utility plant	(53,018)	(8,231)	(88,267)	(60,113)
Proceeds from sale of investment	20,183	–	–	–
Investment in decommissioning trust fund	(5,960)	(553)	(5,159)	(5,018)
Other investing activities	(328)	55	330	137
Net cash used for investing activities	(39,123)	(8,729)	(93,096)	(64,994)
Cash Flows From Financing Activities (Note B):				
Proceeds from issuance of preferred stock	–	97,500	–	–
Proceeds from issuance of long-term debt	–	778,120	–	–
Redemption of obligations subject to compromise	–	(1,131,695)	(1,051)	(955)
Repurchase of long-term debt	(117,522)	–	–	–
Principal payments on long-term note payable	(6)	–	–	–
Proceeds from financing and capital lease obligations	17,365	43,309	–	–
Redemption of financing and capital lease obligations	(14,409)	–	–	–
Capital stock expense	(596)	–	–	–
Net cash used for financing activities	(115,168)	(212,766)	(1,051)	(955)
Net increase (decrease) in cash and temporary investments	14,022	(207,762)	53,923	27,498
Cash and temporary investments at beginning of period	54,745	262,507	208,584	181,086
Cash and temporary investments at end of period	$ 68,767	$ 54,745	$ 262,507	$ 208,584
Supplemental Disclosures of Cash Flow Information:				
Cash (refunded) paid for:				
Income taxes	$ (2,504)	$ –	$ 12,950	$ 4,700
Interest	53,000	8,580	80,688	92,474
Reorganization items - professional fees and other	8,682	2,279	15,207	26,406

See accompanying notes to financial statements.

A. Fresh-Start Reporting

On January 8, 1992 (the "Petition Date"), El Paso Electric Company (the "Predecessor Company") filed a voluntary petition for reorganization (the "Bankruptcy Case") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Western District of Texas, Austin Division (the "Bankruptcy Court"). The Bankruptcy Court entered an order dated January 9, 1996 confirming the Company's Fourth Amended Plan of Reorganization (the "Plan"). On February 12, 1996, the Plan became effective (the "Effective Date") and the Company emerged from bankruptcy (the "Reorganization") as an independent investor-owned utility (the "Reorganized Company" or the "Company").

In connection with the emergence from bankruptcy, the Company adopted fresh-start reporting in accordance with the requirements of Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" ("SOP 90-7"). The application of SOP 90-7 resulted in the creation of a new reporting entity having no retained earnings or accumulated deficit. Accordingly, the financial statements of the Reorganized Company for post-bankruptcy periods, which reflect the application of fresh-start reporting, are not comparable to the financial statements of the Predecessor Company.

In applying fresh-start reporting the Company determined its reorganization value which was allocated to the Company's assets and recorded liabilities at their fair values as of the Effective Date. The Company determined its reorganization value by determining the value of its capital structure, exclusive of operational liabilities, based on management's estimates of future operating results. Debt securities and preferred stock were reflected at face value which approximated fair value and common stockholders' equity was valued at $300 million. The value of the capital structure plus operational liabilities equaled reorganization value. Reorganization value necessarily assumes that the Reorganized Company will achieve its estimated future operating results in all material respects. If such results are not achieved, the value of the Reorganized Company could be materially different.

Reorganization value was allocated first to those assets which have readily determinable fair values, such as cash and investments, receivables and inventories, or assets whose historic values generally approximate their fair values. The remaining balance represents the value attributable to the Company's integrated utility system. The Company determined that no value is attributable to identifiable intangible assets. Such intangible assets do not allow the Company to receive values in excess of what would otherwise be obtained. Therefore, the entire remaining balance was allocated to utility plant in service.

The significant effects of the Reorganization and adjustments made in fresh-start reporting resulted in (i) decreased operation expense and increased depreciation expense due to the reacquisition of previously sold and leased back generation facilities and due to accelerated depreciation expense on a portion of the reorganization value assigned to certain plant assets; (ii) increased interest expense due to the changes in the Company's capital structure; and (iii) increased operating revenues related to a rate increase in the Company's Texas jurisdiction.

The effects of the Reorganization and fresh-start reporting on the Company's balance sheet as of February 11, 1996 are as follows (In thousands):

	Predecessor Company February 11, 1996	(a) Reacquisition of Plant	(b) Discharge of Debt	(c) Settlement with Stockholders	(d) Fresh-Start Adjustments	Reorganized Company February 11, 1996
Utility plant:						
Net plant in service	$1,278,617	$ 227,656	$ –	$ –	$ (54,179)	$1,452,094
Construction work in progress	50,793	–	–	–	–	50,793
Net nuclear fuel	42,668	–	–	–	–	42,668
Net utility plant	1,372,078	227,656	–	–	(54,179)	1,545,555
Current assets:						
Cash and temporary investments	266,442	–	(211,697)	–	–	54,745
Accounts receivable	55,362	–	–	–	5,738	61,100
Inventories	32,647	–	–	–	(4,357)	28,290
Prepayments and other	6,753	–	–	–	–	6,753
Total current assets	361,204	–	(211,697)	–	1,381	150,888
Long-term contract receivable	33,390	–	–	–	–	33,390
Deferred charges and other assets:						
Accumulated deferred income taxes	–	–	–	–	115,354	115,354
Decommissioning trust fund	26,736	–	–	–	–	26,736
Other	7,851	–	14,241	–	16,339	38,431
Total deferred charges and other assets	34,587	–	14,241	–	131,693	180,521
Total assets	$1,801,259	$ 227,656	$ (197,456)	$ –	$ 78,895	$1,910,354
Capitalization:						
Common stock	$ –	$ –	$ 255,000	$ 45,000	$ –	$ 300,000
Predecessor common stock	339,097	–	–	(339,097)	–	–
Accumulated earnings (deficit)	(731,431)	(6,783)	264,273	375,561	98,380	–
Net unrealized gain on marketable securities, net of tax	172	–	–	–	(172)	–
Common stock equity (deficit)	(392,162)	(6,783)	519,273	81,464	98,208	300,000
Preferred stock	–	–	100,000	–	–	100,000
Predecessor preferred stock	81,464	–	–	(81,464)	–	–
Obligations subject to compromise	1,645,277	361,597	(2,006,874)	–	–	–
Long-term debt and financing and capital lease obligations	–	–	1,164,328	–	–	1,164,328
Total capitalization	1,334,579	354,814	(223,273)	–	98,208	1,564,328
Current liabilities:						
Current maturities of financing and capital lease obligations	–	–	24,213	–	–	24,213
Accounts payable	41,253	–	–	–	–	41,253
Taxes accrued other than federal income taxes	24,540	–	–	–	(1,591)	22,949
Net overcollection of fuel revenues	13,327	–	(3,255)	–	712	10,784
Other	14,395	–	332	–	(1,960)	12,767
Total current liabilities	93,515	–	21,290	–	(2,839)	111,966
Deferred credits and other liabilities:						
Accumulated deferred income taxes	67,803	–	–	–	(67,803)	–
Accumulated deferred investment tax credits	77,950	–	–	–	(77,950)	–
Deferred gain on sales and leasebacks	127,673	(127,158)	–	–	(515)	–
Decommissioning	48,349	–	–	–	36,582	84,931
Accrued postretirement benefit liability	21,500	–	–	–	52,340	73,840
Accrued pension liability	7,941	–	5,575	–	21,738	35,254
Other	21,949	–	(1,048)	–	19,134	40,035
Total deferred credits and other liabilities	373,165	(127,158)	4,527	–	(16,474)	234,060
Total capitalization and liabilities	$1,801,259	$ 227,656	$ (197,456)	$ –	$ 78,895	$1,910,354

(a) To record, at fair value, the reacquisition of the previously sold and leased-back generation facilities at the Palo Verde Nuclear Generating Station ("Palo Verde") and the recognition of the related allowed claims in excess of the amounts recorded on the Predecessor Company's balance sheet.

(b) To record the settlement with the Predecessor Company's creditors including the issuance of $945.8 million of first mortgage bonds, $100 million of preferred stock, a draw of $43.3 million on the revolving credit facility related to the financing of nuclear fuel, the issuance of $255 million of the Reorganized Company's common stock, and the carry forward of approximately $206 million of pollution control revenue bonds and other miscellaneous claims of the Predecessor Company.

(c) To record the settlement with the previous common and preferred stockholders of the Predecessor Company including the cancellation of the Predecessor Company's common and preferred stock and the issuance of approximately 3% and 12%, respectively, of the Reorganized Company's common stock.

(d) To record the adjustments that allocate the reorganization value to assets and reflect liabilities at their fair values and to adjust the accumulated deficit to zero.

B. Emergence from Bankruptcy

The Reorganization

The Reorganization became effective immediately prior to the consummation of the sale by the Reorganized Company in an underwritten offering of $794 million of first mortgage bonds and $100 million of 11.4% preferred stock. The net proceeds of approximately $875.6 million were distributed to the Predecessor Company's creditors pursuant to the Plan. In addition, the Reorganized Company issued $151.8 million aggregate principal amount of first mortgage bonds and approximately 60 million shares of common stock, and paid approximately $150 million of cash (in addition to the net cash proceeds of the underwritten offering) to holders of allowed claims and interests in the Reorganization. The interest rates on the five series of First Mortgage Bonds range from 7.25% to 9.40% per annum and maturities range from three to fifteen years.

Under the Reorganization, the Predecessor Company's total obligations subject to compromise of $2,007 million (including obligations related to leases on portions of Palo Verde that represented $700 million of allowed claims in the Bankruptcy Case) were extinguished and the creditors received a combination of cash and newly issued debt and equity securities of the Reorganized Company. The discharge of obligations subject to compromise for less than their recorded amounts resulted in an extraordinary nontaxable gain on discharge of debt of $264.3 million. Pursuant to the Plan, all of the Predecessor Company's Common and Preferred Stock was cancelled and the holders of such securities received approximately 15% of the Reorganized Company's Common Stock and the right to receive certain litigation recoveries, if any.

In addition, in connection with the extinguishment of Palo Verde lease obligations on the Effective Date, in accordance with Palo Verde license amendments issued by the United States Nuclear Regulatory Commission, arrangements pursuant to which the Predecessor Company sold and leased back portions of its interest in Palo Verde were terminated and the Reorganized Company reacquired such interests. The Reorganized Company has agreed to indemnify certain parties to the sale/leaseback transactions against possible tax liabilities related thereto. See Note J.

A final order in Docket No. 12700 (the "Agreed Order") was entered on August 30, 1995 by the Public Utility Commission of Texas (the "Texas Commission") and became effective on the Effective Date. The Agreed Order implemented certain provisions of a settlement (the "Rate Stipulation") dated July 27, 1995 among the Company and substantially all of the other parties to Docket No. 12700. Among other things, under the Rate Stipulation (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for ten years beginning August 2, 1995 (the "Freeze Period"); (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vi) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

The Reorganization also provided for many other matters, including the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption of certain leases and agreements, the reconstitution of the board of directors following the Effective Date and the entry into employment and other arrangements with certain members of management.

Reorganization items (expense), net of income tax benefit (expense), recorded by the Predecessor Company consisted of the following (In thousands):

	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Adjustments of assets and liabilities to fair value	$ (92,013)	$ –	$ –
Rate Stipulation	71,579	–	–
Provisions for settlement of claims	(34,317)	–	–
Deferred income tax benefit related to Reorganization	190,393	–	–
Professional fees and other expenses	(14,348)	(19,776)	(15,866)
Interest earned on accumulated cash resulting from Bankruptcy Case, net of income tax expense	957	9,798	6,875
	$ 122,251	$ (9,978)	$ (8,991)

Non-cash investing and financing activities recorded by the Company consisted of the following (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Issuance of preferred stock for pay-in-kind dividend	$ 8,426	$ –	$ –	$ –
Property purchased through issuance of promissory note	964	–	–	–
Reorganized Common Stock exchanged for Predecessor Common and Preferred Stock	–	45,000	–	–
Reorganized Common Stock exchanged for settlement of obligations subject to compromise	–	255,000	–	–
Long-term debt exchanged for settlement of obligations subject to compromise	–	151,834	–	–
Plant in service reacquired through incurring obligation subject to compromise	–	227,656	–	–

C. Rate Matters

Overview

Texas. The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services in Texas and jurisdiction over certain activities of the Company.

New Mexico. The New Mexico Public Utility Commission (the "New Mexico Commission") has jurisdiction over the Company's rates and services in New Mexico and jurisdiction over certain activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. Current base rates in New Mexico were established in 1990 and have not increased. The Company does not have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation.

Federal Energy Regulatory Commission. The Company is subject to regulation by the Federal Energy Regulatory Commission (the "FERC") in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

Department of Energy. The Department of Energy (the "DOE") traditionally regulates the Company's exports of power to the Comision Federal de Electricidad (the "CFE") in Mexico pursuant to a license granted by the DOE and a presidential permit. In addition, the DOE is authorized to assess operators of nuclear generating facilities for a share of the costs of decommissioning the DOE uranium enrichment facilities over a period of fifteen years.

Nuclear Regulatory Commission. The Nuclear Regulatory Commission (the "NRC") has jurisdiction over the Company's licenses for Palo Verde, regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards and conducts environmental reviews.

Texas Rate Matters

Rate Stipulation and Agreed Order. The Company's rates for its Texas jurisdictional customers are governed by the Agreed Order, which became effective on the Effective Date. The Agreed Order implemented certain provisions of the Rate Stipulation and set rates consistent with the Rate Stipulation. Among other things, under the Rate Stipulation: (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for the Freeze Period; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) the Company's reacquisition of the Palo Verde leased assets is deemed to be in the public interest; (vi) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vii) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

Neither the Rate Stipulation nor the Agreed Order deprives the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined in the Agreed Order that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Rate Stipulation (other than the General Counsel, OPC and the State of Texas) agreed not to seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Rate Stipulation retain all rights provided in the Rate Stipulation, their rights to participate as a party in any proceeding related to the merger, as well as the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings. See "Recent Changes in Utility Regulation."

Fuel. The Company must periodically reconcile its Texas fuel costs pursuant to Texas Commission rules. The Company has not filed a reconciliation, which must contain not less than twelve months nor more than thirty-six months of reconcilable data for any period since June 1995. In a reconciliation, revenues that the Company collected from Texas customers under its fixed fuel factor are reconciled with the expenses for fuel and purchased power actually incurred by the Company for the period covered by the reconciliation. Differences between revenues collected and expenses incurred are subject to a refund to customers (in the case of an overrecovery of fuel costs) or surcharge (in the case of an underrecovery of fuel costs). The Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the recovery of expenses on the basis of unreasonable or improper fuel and purchased power costs.

Higher natural gas prices began in December 1996 and continued in the first quarter of 1997. These higher natural gas prices will increase the Company's underrecovered fuel costs, which will be reviewed in the next Texas fuel reconciliation.

Palo Verde Performance Standards. The Texas Commission has established performance standards for the operation of Palo Verde, pursuant to which Palo Verde is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. There are five performance bands based around a target capacity factor of 70%. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission could reconsider the rate treatment of Palo Verde, regardless of the provisions of the Rate Stipulation. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Based upon the formula for calculating the performance standards in Texas, the Company does not believe a performance penalty will be assessed for the year ended December 31, 1996.

New Mexico Rate Matters

Pending Rate Case. In October 1996, the New Mexico Commission issued an order in Case No. 2722, requiring the Company to answer certain ratepayer complaints and to file a rate filing package, including cost of service data and supporting testimony. On March 3, 1997, the Company filed all of the rate filing package data required by the Commission's order with the Commission. Although the Company's filing demonstrates a revenue deficiency of approximately $8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Fuel. The Company is required to file an annual fuel report and an annual Palo Verde performance standards report, discussed below, with the New Mexico Commission by January 31 of each year for the preceding calendar year. The Company requested and received two extensions of time and filed these reports on March 24, 1997. The Company's filing reflects a significant increase in the monthly fuel charge to be effective with bills rendered on or after May 1, 1997. This increase is necessary because of significant increases in the spot price of natural gas which have caused the Company to underrecover its fuel costs in New Mexico by approximately $2.0 million for the year ended December 31, 1996. The recovery of this amount, coupled with projected higher gas costs for 1997, results in an increase in the proposed 1997 fuel factor of approximately 50% over the present factor. There can be no assurance that the Commission will accept the Company's proposed fuel factor. As in Texas, interested parties are allowed to intervene and challenge the recoverability of expenses as unreasonable or imprudent. Any significant disallowance of recovery could have a material adverse effect on the Company's financial results.

Palo Verde Performance Standards. The New Mexico Commission has established performance standards for the operation of Palo Verde, pursuant to which the entire Palo Verde station is evaluated annually to determine if its achieved capacity factor allows the Company to claim a credit or subjects the Company to a penalty. Because Unit 3 is not included in the Company's New Mexico rate base, any penalty or credit calculated on a total station basis is limited to two-thirds of such penalty or credit. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the annual capacity factor is 35% or less, the New Mexico Commission is required to initiate a proceeding to reconsider the rate base treatment of Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. For the year ended December 31, 1996, the Palo Verde station capacity factor was 86.20%. This capacity factor resulted in the Company's entitlement to a credit. However, the Company is voluntarily foregoing collection of this credit to partially mitigate the increase in the proposed New Mexico fuel factor, discussed above.

Federal Regulatory Matters

FERC. The Company has a long-term firm power sales agreement with IID providing for the sale of 100 MW of firm capacity and 50 MW of contingent capacity through April 2002. The agreement generally provides for level sales prices over the life of the agreement. The Company has a firm power sales agreement with TNP, providing for sales to TNP in the minimum amount of 25 MW through 2002. Sales prices are essentially level for the remaining life of the agreement. Rate tariffs currently applicable to IID and TNP contain fuel and purchased power cost adjustment provisions designed to recover the Company's fuel and purchased power costs.

In July 1996, the Company filed its open access transmission tariffs (Docket No. OA96-200-000) in compliance with Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* ("Order No. 888"), covering network and point-to-point transmission services and the six specifically required ancillary services. Several parties, including Las Cruces, other utilities and several wholesale power marketers intervened and filed protests to the Company's tariffs. Issues raised by the intervenors included rates and the terms and conditions of the Company's tariffs, including the treatment and costs related to certain facilities making access to the CFE more available to parties other than the Company. In February 1997, the Company entered into a stipulated agreement among the various parties settling all issues related to Docket No. OA96-200-000. Under the settlement the Company will provide transmission service, to the extent transmission capacity is available, to any party for firm or interruptible service to the CFE until the earlier of the end of 1998 or the date the FERC rules on the complaint filed by Enron. See Note K.

In December 1996, Las Cruces filed a request at the FERC for a determination that Las Cruces would have no stranded cost obligation to the Company in the event the city leaves the Company's system and operates its own municipal utility. The Company calculated Las Cruces' stranded cost obligation to be approximately $234 million. The FERC is expected to establish a procedural schedule for discovery and hearings in this matter. The Company is unable to predict the outcome of this proceeding or the impact it may have on the Company. See Note K.

Also in December 1996, Southwestern Public Service Company ("SPS") filed a request for the issuance of an order by the FERC requiring the Company to accept as a "completed application" for service under the Company's open access transmission tariff a September 1996 request by SPS for service that may be needed for SPS to deliver electricity to a newly-formed Las Cruces municipal electric system. The Company stated in response to that request that SPS had failed to provide certain information required to be submitted by persons seeking service under its open access transmission tariff. The Company has asked that the proceedings initiated by Las Cruces and by SPS, respectively, be consolidated. Both matters are currently pending before the FERC.

Department of Energy. In October 1996, the FERC issued an order requiring the Company to provide Enron Power Marketing, Inc., a wholesale power marketer, with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction.

Promptly after the issuance of the FERC order, Enron asked the DOE to exercise its authority over Presidential Permits relating to construction of border-crossing transmission facilities and over export authorizations issued to the Company and to Enron to require transmission access for delivery of electricity to the CFE in Mexico. Pursuant to Enron's request, the DOE, on October 30, 1996, issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties with respect to Presidential Permits and export authorizations issued to the Company. The Company has filed responses to Enron's request at both the FERC and the DOE in which it has asserted that the DOE has no authority to require transmission of electric energy for delivery to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder during 1997, if someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position, which remains that under the current law the provision of such access is not required. Neither the FERC nor the DOE has taken any final action on this matter.

Other Wholesale Customers

The primary term of the Company's previous five year sales agreement for firm capacity and associated energy to the CFE terminated December 31, 1996. In September 1996, the CFE issued a request for proposals for replacement power for 1997. The Company submitted a bid and was ultimately selected by the CFE to provide varying amounts of power during 1997 ranging from 120 to 200 MW. Since the CFE load provided by the Company will be isolated from the rest of the CFE system, the Company is also providing the CFE with the flexibility to increase its power deliveries up to 5% above its monthly contract capacity level in order to meet its customer power requirements. The price is stable throughout the term of the agreement and includes charges for capacity and energy as well as transmission and any required ancillary services. Under the new agreement with the CFE, revenues in 1997 related to power sales to the CFE are expected to be lower than revenues recorded in 1996. The agreement requires payment in United States dollars. See Notes K and M.

Recent Changes in Utility Regulation

General. The electric utility industry faces increasing pressure to become more competitive as legislative, regulatory, economic and technological changes occur. Federal legislation, as well as legislative and regulatory initiatives in various states and proposed initiatives in Texas and New Mexico, encourages competition in the Company's service area for electricity generation among electric utility and non-utility power producers. Together with increasing customer demand for lower-priced electricity and other energy services, these measures have accelerated the industry's movement toward more competitive pricing and cost structures. Such competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets, as well as the cost of operating these assets. This issue is particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flows and financial condition of the Company, or that the Company will be able to sustain retail rates at the levels established by the Rate Stipulation during the Freeze Period.

Of particular importance to the Company is the issue of ultimate recoverability of costs previously found by regulatory authorities to be reasonable and prudent, but which at the same time are higher than would be recovered under immediate, full competition (i.e., stranded costs). Across the industry, as well as at the state level, there is much discussion and debate on this issue. At this time, there appears to be no clear solution. At the federal level, the FERC has announced, through a formal rulemaking, its intention to allow 100% recovery of all legitimate verifiable stranded costs attributable to FERC jurisdictional customers. Texas and New Mexico are engaged in various activities, at the commission and legislative level, which are attempting to address the issue of stranded cost recovery from customers subject to state legislation.

FERC. In April 1996, pursuant to its authority under Sections 205 and 206 of the FPA, the FERC issued its Order No. 888. Order No. 888 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to (i) file open access transmission tariffs containing minimum terms and conditions of non-discriminatory service and (ii) take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. Additionally, Order No. 888 permits public utilities to seek recovery of legitimate, prudent and verifiable stranded costs and provides a mechanism for the recovery of such costs. Order No. 888 also provides for recovery of costs associated with former power customers and new municipally-owned entities becoming transmission-only customers as a result of providing open access transmission if the utility had a reasonable expectation of continuing to provide service to the departing customer. Order No. 888

established criteria under which stranded costs will be evaluated for contracts entered into prior to July 11, 1994, and for stranded costs resulting from the formation of any new municipal utilities. Recovery of stranded costs under contracts entered into after July 10, 1994, will be governed by the terms of those contracts.

In April 1996, the FERC also issued Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct* ("Order No. 889"). Order No. 889 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to develop and maintain an Open Access Same-Time Information System that will give existing and potential transmission users access to transmission related information on a basis consistent with that available to a utility's employees engaged in the buying and selling of power. Order No. 889 further requires public utilities to separate their transmission and generation marketing functions and communications and adopt standards of conduct ensuring that all open access transmission customers are treated in a non-discriminatory manner.

Texas. In February 1996, the Texas Commission adopted a rule governing wholesale transmission access, as required by recent Texas legislation. The Texas Commission does not have jurisdiction over the Company's wholesale transactions. However, the rule required the Company to file its FERC-approved open access transmission tariffs with the Texas Commission to certify compliance with the Texas legislation.

During 1996, pursuant to the directives of the Texas Legislature in legislation passed in 1995, the Texas Commission conducted projects to evaluate the (i) scope of competition in the electric industry in Texas and (ii) potential for stranded investment, procedures for allocating stranded costs and acceptable methods of stranded cost recovery. The Texas Commission's report consolidating the two projects was issued in January 1997. While it recommended a careful and deliberate approach to continued expansion of competition in the Texas electric market, ultimately leading to retail competition with certain safeguards, it also recommended against any legislation that would introduce broad based retail competition before 2000. The Texas Commission quantified the potential "excess of cost over market" ("ECOM") at both wholesale and retail levels under several scenarios. With respect to the Company's potential for stranded costs, the Texas Commission estimated no wholesale ECOM, and estimated retail ECOM ranging from a high of $1.3 billion to a low of $781.0 million, with an expected value of $1.1 billion, assuming full retail access in 1998. The Company cannot determine at this time the effects that would occur, including any possible effects on the Rate Stipulation, as the result of any broad based competition legislative action, if any, implemented in 1997.

New Mexico. The New Mexico Commission initiated a notice of inquiry regarding competition and the restructuring of regulation of the electric industry in 1996. The New Mexico Commission received comments from numerous parties representing various interests and conducted workshops in an attempt to arrive at a consensus with respect to the need for regulatory change, the nature of such change and the timing/transition of any changes. No consensus was reached by the participants. With respect to stranded costs, the New Mexico Commission applied the same ECOM model that was developed for Texas. The Company's New Mexico ECOM calculation ranged from a high of $248 million to a low of $173 million. The Company also provided the New Mexico Commission with its calculation of stranded costs for New Mexico pursuant to FERC Order No. 888, which equaled $364 million.

D. Summary of Significant Accounting Policies

General. The Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. As of December 31, 1996, the Company served approximately 279,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico. The Company also serves wholesale customers in Texas, New Mexico, California and Juarez, Mexico.

The preparation of financial statements in conformity with generally accepted accounting principles 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.

The Company maintains its accounts in accordance with the Uniform System of Accounts prescribed for electric utilities by the FERC. Prior to December 31, 1991, the Company reported its regulated utility operations pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71"). The Company discontinued the application of SFAS No. 71 as of December 31, 1991.

As more fully discussed in Note A, the Company emerged from bankruptcy on February 12, 1996. The Company has accounted for all transactions related to the reorganization proceedings in accordance with SOP 90-7. The Reorganization had significant impacts on the financial statements of the Reorganized Company, including the creation of a new reporting entity upon emergence from bankruptcy through the application of fresh-start reporting pursuant to SOP 90-7. Accordingly, the Company's post-Reorganization balance sheets and the statement of operations, which reflect the application of fresh-start reporting, have not been prepared on a consistent basis with the pre-Reorganization financial statements and are not comparable in all respects to the financial statements prior to the Reorganization. For accounting purposes, the inception date of the Reorganized Company is deemed to be February 12, 1996. A vertical line is shown in the financial statements to separate the Reorganized Company from the Predecessor Company, since the financial statements have not been prepared on a consistent basis of accounting.

Utility Plant. As a result of adopting fresh-start reporting, as discussed in Note A, the Company has revalued its utility plant. As of February 12, 1996, the value allocated to the assets used in the Company's generation, transmission and distribution operations is based on the Company's estimate of the replacement cost less depreciation ("RCLD") and is derived from the value of the Company as a going concern rather than on an appraisal or other professional valuation of its assets. The RCLD of generation assets was calculated based on estimates of the current cost of gas-fired combined-cycle and combustion turbine power plants, adjusted for certain economic factors. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging from 11 years to 31 years), except for approximately $384 million of reorganization value allocated to net transmission, distribution and general plant in service. This amount is being depreciated over the ten-year period of the Rate Stipulation.

Prior to February 12, 1996, utility plant was stated at original cost, less regulatory disallowances. Costs included labor, material, construction overheads, and allowance for funds used during construction ("AFUDC") or capitalized interest (see Capitalized Interest below). Depreciation was provided on a straight-line basis at annual rates which amortized the undepreciated cost of depreciable property over the estimated remaining service lives, which ranged from 3 years to 49 years. Palo Verde was being amortized on a straight-line basis over approximately 40 years.

The Company charges the cost of repairs and minor replacements to the appropriate operating expense accounts and capitalizes the cost of renewals and betterments. Gains or losses resulting from retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

In connection with the emergence from bankruptcy, the Company accrued a liability for the present value of the estimated decommissioning costs for the Company's interest in Palo Verde. Accretion of the decommissioning liability is charged to interest charges in the statement of operations.

The cost of nuclear fuel is amortized to fuel expense on a unit-of-production basis. A provision for spent fuel disposal costs is charged to expense based on requirements of the DOE for disposal cost of one-tenth of one cent on each kilowatt hour generated.

Capitalized Interest. As a result of discontinuation of the application of SFAS No. 71, the Company discontinued accruing AFUDC in 1992. In place of AFUDC, the Company capitalizes to construction work in progress ("CWIP") and nuclear fuel in process interest cost calculated in accordance with SFAS No. 34, "Capitalization of Interest Cost."

Cash and Cash Equivalents. All temporary cash investments with an original maturity of three months or less are considered cash equivalents.

Investments. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair market value and consist primarily of municipal bonds in trust funds established for decommissioning of its interest in Palo Verde which have a fair market value of approximately $33.1 million at December 31, 1996. Such marketable securities are classified as "available-for-sale" securities and as such the difference between cost and market value is shown as a separate component of capitalization.

Inventories. Inventories, primarily parts, materials and supplies, are stated at average cost not to exceed recoverable costs.

Operating Revenues. The Company accrues revenues for services rendered but unbilled.

The regulations of the Texas Commission, New Mexico Commission and FERC and the agreements with individual customers generally provide for fuel and purchased and interchanged power expenses to be recovered from customers. Fuel revenues reflect the Company's estimate of recoverable fuel and purchased and interchanged power expenses net of a percentage of (i) profit margins from certain off-system sales and

(ii) revenues from third party transmission services, which is credited to customers. Economy sales relate to spot market sales and is included in fuel revenues. Base revenues refer to the Company's revenues from the sale of electricity excluding such fuel revenues.

Federal Income Taxes. The Company accounts for federal income taxes under SFAS No. 109, which requires the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. SFAS No. 109 requires the Company to record a valuation allowance to reduce its deferred tax assets to the extent it is more likely than not that such deferred tax assets will not be realized. SFAS No. 109 recognizes the effect on deferred tax assets and liabilities of a change in tax rate in income in the period that includes the enactment date.

Benefit Plans. See Note L for accounting policies regarding the Company's retirement plans and postretirement benefits.

Earnings per Share. Earnings (loss) per common share is computed by dividing net income or loss, after deducting the preferred dividend requirements, by the weighted average number of common shares and dilutive common share equivalents outstanding.

For the Reorganized Company, for the period February 12 through December 31, 1996, the computation of fully-diluted earnings per share was immaterially different from primary earnings per share.

For the Predecessor Company, there was no difference between primary and fully-diluted earnings per share.

Stock Option Plans. The Company has an option plan which reserves shares of common stock for issuance to officers. The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, compensation cost is recognized for the intrinsic value, if any, of option grants at measurement date ratably over the vesting period of the options.

Impairment of Long-Lived Assets. The Company adopted the provisions of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," upon the emergence from bankruptcy. SFAS No. 121 requires that long-lived assets and certain identifiable intangibles be 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. The Company's application of fresh-start reporting upon the emergence from bankruptcy encompassed the adoption of SFAS No. 121 and as such the Company's adoption of SFAS No. 121 did not have a significant impact on its financial statements.

Reclassifications. Certain amounts in the financial statements for 1995 and 1994 have been reclassified to conform with the 1996 presentation.

E. Palo Verde and Other Jointly Owned Utility Plant

The Company has a 15.8% undivided interest in the three 1,270 MW nuclear generating units at Palo Verde in which six other utilities (collectively, the "Palo Verde Participants") have interests, including Arizona Public Service Company ("APS"), who is the operating agent of Palo Verde. The operation of Palo Verde and the relationship among the Palo Verde Participants is governed by the ANPP Participation Agreement.

Pursuant to the Plan, the Predecessor Company's Palo Verde lease obligations were extinguished on the Effective Date and the Reorganized Company reacquired the previously sold and leased back portions of Palo Verde. In accordance with fresh-start reporting the Reorganized Company recorded the reacquired portions of Palo Verde at fair market value, which was approximately $227.7 million and revalued the Company's interest in Palo Verde at RCLD. See Note A and the Utility Plant portion of Note D for a discussion of the valuation of the Company's utility plant. As of December 31, 1995, the Company's investment, at cost, in Palo Verde in the amount of approximately $963.0 million, excludes amounts related to the Company's investment in Palo Verde which was sold and leased back during 1986 and 1987 and for which the related leases were accounted for as operating leases.

Other jointly owned utility plant includes a 7% undivided interest in Units 4 and 5 of the Four Corners Project ("Four Corners") and certain other transmission facilities. A summary of the Company's investment in jointly owned utility plant, excluding fuel, at December 31, 1996 and 1995 is as follows (In thousands):

	Reorganized Company December 31, 1996		Predecessor Company December 31, 1995	
	Palo Verde Station	Other	Palo Verde Station	Other
Electric plant in service	$ 568,957	$ 173,409	$ 952,310	$ 135,400
Accumulated depreciation	(22,162)	(10,607)	(155,749)	(59,398)
Construction work in progress	8,545	985	10,653	1,661

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units and each Palo Verde Participant is required to fund its proportionate share of fuel, other operation, maintenance and capital costs, which, except capital costs, are included in the corresponding expense captions in the statements of operations. The Company's total monthly share of these costs was approximately $6.9 million in 1996. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

Decommissioning. Prior to Reorganization, the Predecessor Company was accruing its estimated decommissioning obligation over the remaining service life (approximately 40 years) for the portion of its owned interest in Palo Verde and over the term of the related leases (27 to 29 years) for the portions of Palo Verde that were sold and leased back. Upon the adoption of fresh-start reporting, the Company recorded the net present value of estimated future expenditures for decommissioning, using a risk free rate of return of 6.00%, and began accruing interest on the decommissioning liability. The Reorganized Company's interest expense includes approximately $4.6 million related to the accretion of the nuclear decommissioning liability. As of December 31, 1996, the Company has accrued a liability of approximately $89.5 million for its estimated decommissioning costs.

In December 1995, the Palo Verde Participants approved a study by an outside engineering firm of the cost of decommissioning Palo Verde. The 1995 study determined that the Company will have to fund approximately $229 million (stated in 1995 dollars) to cover its share of such costs beginning in 2024 through 2037. The 1995 study assumes that (i) maintenance expense for spent fuel storage will be incurred for ten years after the shutdown of the last unit (estimated to be in 2024) rather than the approximately 30 years utilized in a 1993 study; (ii) a national interim spent fuel storage facility will be available; and (iii) as a result of such national spent fuel storage facility, the amount of spent fuel stored on-site is reduced from all spent fuel assemblies to the final core plus fuel assemblies from approximately three refuelings.

Cost estimates for decommissioning have increased with each study, although the 1995 cost estimate is comparable to the previous cost estimate from a 1993 study (which determined that the Company would have to fund approximately $221 million, stated in 1993 dollars). The 1993 study was based on different assumptions, primarily related to the decommissioning of spent fuel. The 1993 cost estimate included an estimated cost of approximately $50 million related to on-site spent fuel storage facilities, while the 1995 study includes an estimated cost of approximately $13 million related to spent fuel. This difference in estimates is primarily due to the different timing assumptions discussed above. The 1993 estimate reflected an 84% increase from the previous estimate made in 1989, primarily due to an increase in the estimated costs associated with the permanent burial of low-level radioactive waste due to the uncertainty surrounding the availability and cost of low-level radioactive waste repositories, as discussed below.

Although the 1995 study is based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste may increase significantly.

The rate freeze under the Rate Stipulation would preclude the Company from seeking a rate increase in Texas during the Freeze Period to recover increases in decommissioning cost estimates. Additionally, there can be no assurance that the Company could increase its rates in any of its other jurisdictions to recover such increased costs.

The Company has established external trusts with independent trustees, which enable the Company to record a current deduction for federal income tax purposes of a portion of amounts funded. As of December 31, 1996, the aggregate balance of the trust funds was approximately $33.1 million, which is reflected in the Company's balance sheets in deferred charges and other assets.

An industry-wide assessment has been made for decontamination of the DOE's enrichment facilities. The total amount of this assessment has not yet been finalized; however, APS estimates that the annual assessment for Palo Verde will be approximately $3.0 million, plus increases for inflation, for the next fifteen years. The Company has accrued $5.3 million which represents the present value of its remaining portion of the estimated total assessment.

Steam Generators. Palo Verde has experienced degradation in the steam generator tubes of each unit. The degradation includes axial tube cracking in the upper regions of the two steam generators in Unit 2 and, to a lesser degree, in Units 1 and 3. This form of steam generator tube degradation has recently been seen at other U.S. nuclear generating stations. The units also have experienced circumferential cracking at the tube sheet, a more common type of tube cracking. The axial tube cracking was discovered following a steam generator tube rupture in Unit 2 in March 1993. Since that time, APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS has stated that it believes its remedial actions have slowed the rate of tube degradation.

Each of the Palo Verde units has been inspected during regularly scheduled refueling outages and mid-cycle inspection outages. If tube cracks are detected during an inspection, the affected tubes are taken out of service by plugging. This may impair the performance of a unit if sufficient numbers of steam generator tubes are affected.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during outages of the Palo Verde units. In August 1995, APS announced that its ongoing analyses indicated that it will be economically desirable to replace the Unit 2 steam generators, which have been the most affected by tube cracking, in four to nine years. APS further stated that it expects replacement of the steam generators will be performed in conjunction with a normal refueling outage to limit incremental outage time. APS also has stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated life of 40 years (to 2025 and 2027, respectively). APS will continue to assess these steam generators periodically.

Steam generator replacement could be done through new steam generators manufactured for Palo Verde or through the purchase of existing steam generators that are compatible with Palo Verde's design. The Company believes replacement of the steam generators would require the unanimous approval of the Palo Verde Participants. The Company has not yet completed its analysis of the economic feasibility of steam generator replacement, or other options that may be available in connection with the operation of Unit 2. Also, the Company cannot predict whether it or other Palo Verde Participants will agree to replace the Unit 2 steam generators. The Company expects that if the steam generators in Unit 2 are replaced, most of such costs would be incurred between 1998 and 2005. The Company's portion of total costs associated with replacement of the Unit 2 steam generators, including replacement power costs, is currently estimated not to exceed $30 million.

The Rate Stipulation, however, precludes the Company from seeking a rate increase in Texas during the Freeze Period to recover capital costs associated with such replacement should it be necessary.

It is uncertain whether the costs associated with replacing the Unit 2 steam generators would be approved by the New Mexico Commission and included in the Company's rate base in New Mexico.

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability of $200 million under federal law in the form of primary liability insurance provided by commercial insurance carriers. Additionally, the Company participates in an industry-wide retrospective assessment program, under which industry participants would be required to pay an assessment to cover any loss in excess of $200 million. The maximum assessment per reactor for each nuclear incident is approximately $79.2 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential assessment per incident is approximately $37.6 million, with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.7 billion, a substantial portion of the proceeds of which must first be applied to stabilization and decontamination. Finally, the Company has insurance against a portion of any increased cost of generation or purchased power which may result from the accidental outage of any of the three Palo Verde units if the outage exceeds 21 weeks.

F. Common Stock

Overview

The Company issued 60 million shares of new common stock on February 12, 1996. The Common Stock has a stated value of $1 per share, with no cumulative voting rights or preemptive rights. Holders of the Common Stock have the right to elect the Company's directors and to vote on other matters.

The Company's ability to pay dividends on the Common Stock for the next several years will be limited by the terms of applicable laws and financing arrangements entered into pursuant to the Reorganization. All distributions with respect to the Common Stock, including the declaration or payment of dividends, are subject to the provisions of the Texas Business Corporation Act, including provisions that prohibit any distribution that exceeds the surplus of the Company. In addition, under Section 305 of the Federal Power Act, it is unlawful for a director or officer of the Company to participate in the making or payment of dividends from "any funds properly included in capital account." As a result of Reorganization, the Company's first priority at this time is debt retirement and deleveraging as opposed to paying dividends.

Pursuant to the resolutions creating the Series A Preferred Stock, no dividends can be paid on the Common Stock if there are dividends in arrears on the Series A Preferred Stock. So long as the Company's First Mortgage Bonds, Series A through H, are outstanding and the series with the longest maturity is not rated "investment grade" by either Standard & Poor's Rating Service or Moody's Investors Service, Inc., the Company may not declare any dividend on the Common Stock, other than in additional shares of common stock, or make any other distribution on, or acquire for value any shares of common stock (with certain limited exceptions) unless, after giving effect thereto, the aggregate of all such dividends, distributions and certain other payments made by the Company since February 12, 1996 would be less than the sum of (i) 50% of the consolidated net income (as defined in the mortgage indenture) of the Company minus dividends paid in respect of the Series A Preferred Stock for the period from February 13, 1996 to the most recently ended fiscal quarter for which quarterly financial statements are available (or, if such consolidated net income is a deficit, less 100% of such deficit), plus (ii) 100% of the aggregate net proceeds received by the Company from the issuance or sale since February 12, 1996 of equity securities or debt securities that have been converted into equity securities, plus (iii) $10.0 million. Currently, the Company's First Mortgage Bonds are not rated investment grade.

Pursuant to the terms of the reimbursement agreements related to four letters of credit issued in respect of the four series of pollution control revenue bonds, so long as a drawing is available under any of the letters of credit, the same limitation on the declaration of dividends would apply to the Company. In addition to the restriction contained in the mortgage indenture, the reimbursement agreements limit to $15.0 million the aggregate amount of dividends that can be paid on the Common Stock during the three years after its initial issuance on February 12, 1996. The credit agreement for the working capital and fuel financing facility contains the same limitations on the payment of Common Stock dividends as the reimbursement agreements related to the letters of credit on the pollution control revenue bonds.

1996 Long-Term Incentive Plan

The 1996 Long-Term Incentive Plan (the "1996 Plan") authorized the issuance of up to 3,500,000 shares of common stock for the benefit of officers, key employees and non-employee directors through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock and performance stock. During 1996, the Company granted options covering 1,900,000 shares and awarded 180,000 restricted shares under the 1996 Plan.

Stock Option Plans. At December 31, 1996, options were outstanding for the purchase of 1,900,000 shares of common stock of which 660,000 were exercisable as of December 31, 1996. No options were exercised in 1996. All options expire five years from the date of grant unless terminated earlier by the Board of Directors.

The Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Accordingly, because the stock option grants had no intrinsic value at the measurement date, no compensation cost has been recognized. Had compensation cost for the plan been determined based on the fair value at the grant date for the awards in 1996 consistent with the provisions of SFAS No. 123, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts presented below:

		Period From February 12 to December 31, 1996
Net income applicable to common stock (In thousands):		
As reported	$	31,431
Pro forma		30,262
Earnings per share:		
As reported		0.52
Pro forma		0.50

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions: (i) risk-free rate of return is 6.65% for options awarded April 30, 1996 and 6.99% for options awarded June 11, 1996; and (ii) volatility is 4.09% for options awarded on the April grant date and 4.35% for options awarded on the June grant date, calculated using the standard deviation of the Company's Common Stock from February 16, 1996 to the award date. The weighted-average grant-date fair value of options granted during the year was $2.60 per option. The exercise price is the market price on the date of award, which was $5.32 for 800,000 shares on the April grant date and $5.56 for 800,000 shares on the June grant date, except for 300,000 options awarded to the former Chief Executive Officer ("CEO") of the Company with an exercise price of $7.00. All options vest over a period of five years from the date of grant, subject to earlier vesting in accordance with the current CEO's employment agreement, and except for options awarded the former CEO which were fully vested on the date of grant.

Restricted Shares. At December 31, 1996, 180,000 shares of restricted stock were awarded under the 1996 Plan. Restrictions from resale on 20,000 shares have lapsed as of January 1, 1997.

The value of restricted shares is calculated by multiplying (i) 55,000 shares at $5.00 per share for shares awarded February 12, 1996; (ii) 100,000 shares at $5.32 per share for shares awarded on the April grant date; and (iii) 25,000 shares at $5.63 per share for shares awarded May 1, 1996. Restrictions from resale will lapse over five years beginning December 31, 1996, except for 25,000 shares which restrictions will lapse on May 1, 1997.

Unearned compensation was charged for the value of the restricted shares as these shares were issued in accordance with the 1996 Plan. The unearned compensation is shown as a reduction of common stock equity in the accompanying balance sheet and is being amortized ratably over the restricted period. During 1996, approximately $0.2 million relating to restricted stock was charged to expense.

The holder of a restricted stock award will have rights as a shareholder of the Company, including the right to vote and, if applicable, receive cash dividends on restricted stock, except that certain restricted stock awards require any cash dividend on restricted stock to be delivered to the Company in exchange for additional shares of restricted stock of equivalent market value.

Changes in common stock are as follows:

	Common Stock Shares	Common Stock	Capital in Excess of Stated Value	Unearned Compensation-Restricted Stock Awards
			(In thousands)	
Balance December 31, 1993, 1994 and 1995	35,544,330	$ 339,097	$ –	$ –
Redemption of Predecessor Common Stock	(35,544,330)	(339,097)	–	–
Issuance of Reorganized Common Stock	59,999,981	60,000	240,000	–
Restricted shares	180,000	180	768	(948)
Restricted stock compensation accrued	–	–	–	190
Balance December 31, 1996	60,179,981	$ 60,180	$ 240,768	$ (758)

G. Preferred Stock

The Company issued one million shares of new preferred stock on February 12, 1996. The Preferred Stock has a liquidation preference of $100 per share, has no sinking fund requirements and must be redeemed by the Company in 2008. The Preferred Stock has an annual dividend rate of 11.40%, which is to be paid through the issuance of additional shares of preferred stock for the first three years and in cash thereafter. On November 1, 1996, the Company paid the first pay-in-kind dividend by issuing 84,264 shares to satisfy the dividend. Also, on January 16, 1997, the Company's Board of Directors declared the second pay-in-kind dividend which was paid on February 1, 1997 through the issuance of 30,886 additional shares to shareholders of record as of January 21, 1997.

Preferred Stock, Redemption Required

Following is a summary of the redemption of the Predecessor Company Preferred Stock and the issued and outstanding Preferred Stock, redemption required, of the Reorganized Company:

	Shares	Amount
		(In thousands)
Balance at December 31, 1993, 1994 and 1995	639,600	$ 67,266
Redemption of Predecessor Preferred Stock	(639,600)	(67,266)
Issuance of Reorganized Preferred Stock	1,000,000	100,000
Issuance of Dividend	84,264	8,426
Balance at December 31, 1996	1,084,264	$ 108,426

Optional Redemption. The Series A Preferred Stock is not redeemable at the Company's option prior to February 1, 1999; provided, however, that upon the occurrence of a change of control on or prior to February 1, 1999, the Company shall have the right to redeem the outstanding Series A Preferred Stock, in whole or in part, no earlier than 30 days nor later than 60 days from the date the change of control offer is mailed to the holders of Series A Preferred Stock, in cash, at a price per share equal to the sum of (i) 108% of the liquidation preference plus (ii) accrued and unpaid dividends (including an amount equal to a prorated dividend from the immediately preceding dividend accrual date), if any, to the redemption date. Thereafter, the outstanding Series A Preferred Stock may be redeemed, in whole or in part, at the option of the Company, in cash at the redemption prices set forth in the table below, plus all accrued and unpaid dividends (including an amount equal to a prorated dividend from the immediately preceding dividend accrual date to the date of redemption), if any, if redeemed during the twelve-month period beginning on February 1 of the years indicated below:

Year	Optional Redemption Price
1999	105.70%
2000	104.56
2001	103.42
2002	102.28
2003	101.14
2004 and thereafter	100.00

Mandatory Redemption. On February 1, 2008, the Company will be required to redeem (subject to the legal availability of funds therefor) all outstanding shares of Series A Preferred Stock at a price in cash equal to the sum of (i) the liquidation preference thereof plus (ii) all accrued and unpaid dividends, if any, to the date of redemption.

Preferred Stock, Redemption not Required

Following is a summary of the Predecessor Company Preferred Stock, redemption not required:

	Shares	Amount (In thousands)
Balance at December 31, 1993, 1994 and 1995	142,450	$ 14,198
Redemption of Predecessor Preferred Stock	(142,450)	(14,198)
Balance at December 31, 1996	–	$ –

H. Long-Term and Financing and Capital Lease Obligations

Outstanding long-term and financing and capital lease obligations are as follows:

	December 31, 1996 (In thousands)
Long-Term Obligations:	
First Mortgage Bonds (1):	
7.25% Series A, issued 1996, due 1999	$ 78,266
7.75% Series B, issued 1996, due 2001	78,771
8.25% Series C, issued 1996, due 2003	148,989
8.90% Series D, issued 1996, due 2006	235,957
9.40% Series E, issued 1996, due 2011	285,900
Pollution Control Bonds (2):	
Secured by First Mortgage Collateral Bonds:	
Variable rate bonds, due 2014	63,500
Variable rate refunding bonds, due 2013	33,300
Variable rate refunding bonds, due 2014	37,100
Variable rate refunding bonds, due 2015	59,235
Promissory note due 2007 ($227,000 due in 1997) (3)	958
Total long-term obligations	1,021,976
Financing and Capital Lease Obligations:	
Turbine lease ($1,721,000 due in 1997) (4)	5,900
Nuclear fuel ($26,385,000 due in 1997) (5)	46,630
Total financing and capital lease obligations	52,530
Total long-term and financing and capital lease obligations	1,074,506
Current maturities (Amount due within one year)	(28,333)
	$ 1,046,173

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(1) First Mortgage Bonds

Substantially all of the Company's utility plant is subject to liens under the First Mortgage Indenture.

The First Mortgage Indenture imposes certain limitations on the ability of the Company to (i) declare or pay dividends on common stock; (ii) incur additional indebtedness or liens on mortgaged property; and (iii) to enter into a consolidation, merger or sale of assets.

Series A, B, C and D Bonds may not be redeemed by the Company prior to maturity. Series E Bonds may be redeemed at the option of the Company, in whole or in part, on or after February 1, 2006.

The Company is not required to make mandatory redemption or sinking fund payments with respect to the bonds prior to maturity.

During the period from February 12, 1996 through December 31, 1996, the Company repurchased approximately $46.7 million of Series A Bonds, and approximately $71.2 million of Series B Bonds.

(2) Pollution Control Bonds

The Company has four series of tax exempt Pollution Control Bonds in an aggregate principal amount of approximately $193.1 million. Each of the tax exempt issues is enhanced by a letter of credit. The Company's obligation to the issuing banks pursuant to the letter of credit reimbursement agreements are secured by First Mortgage Collateral Series Bonds (the "Collateral Series Bonds") issued pursuant to the First Mortgage Indenture in the amount of the letters of credit. The bonds bear interest at rates that are repriced weekly (4.15% to 4.25% at December 31, 1996). The bonds may be required to be repurchased at the holder's option and are subject to mandatory redemption upon the occurrence of certain events and are redeemable at the option of the Company under certain circumstances.

(3) Promissory Note

The secured note due 2007 has an annual interest rate of 5.5%.

(4) Capitalized Lease Obligation, Copper Turbine

In 1980, the Company sold and leased back a turbine and certain other related equipment from the trust-lessor for a twenty-year period, with renewal options for up to seven more years. Semiannual lease payments, including interest, which began in January 1982, were approximately $0.7 million through January 1991, and are approximately $0.9 million thereafter to July 2000. The effective annual interest rate implicit in this lease is calculated to be 9.6%.

(5) Nuclear Fuel Financing

The Company entered into a lease arrangement with a third party grantor trust, Rio Grande Resources Trust ("RGRT II"), with respect to nuclear fuel purchases for Palo Verde. The Company accounts for the lease as a capital lease and has a commitment for a three-year credit facility in the amount of $100 million, which is secured by Collateral Series Bonds, to finance nuclear fuel purchases. The credit facility provides up to $60 million for nuclear fuel purchases and up to $50 million (depending on the amount of borrowings outstanding for nuclear fuel purchases) for working capital needs and may be extended for one year at the option of the Company. Approximately $46.6 million has been drawn to finance nuclear fuel (interest rate of 8.25%) at December 31, 1996. Quarterly lease payments made are based on units of heat production.

Scheduled maturities of long-term and financing and capital lease obligations at December 31, 1996 are as follows (In thousands):

1997	$ 28,333
1998	22,050
1999	80,076
2000	954
2001	78,869

The table above does not reflect future nuclear fuel purchases and related obligations and maturities.

I. Federal Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 1996 and December 31, 1995, are presented below (In thousands):

	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Deferred tax assets:		
Letters of credit draws	$ –	$ 100,946
Gain on sale and leaseback transactions	–	46,410
Accrued lease expense, net of interim payments (Note B)	–	85,942
Reorganization expenses financed with bonds	22,526	–
Accumulated deferred investment tax credits	–	27,396
Capital leases	2,873	25,100
Benefits of tax loss carryforwards	256,510	3,582
Investment tax credit carryforward	20,410	11,984
Alternative minimum tax credit carryforward	9,627	35,964
Other	92,643	100,900
Total gross deferred tax assets	404,589	438,224
Less valuation allowance:		
Federal	12,661	217,509
State	17,941	39,808
Total valuation allowance	30,602	257,317
Net deferred tax assets	373,987	180,907
Deferred tax liabilities:		
Plant, principally due to differences in depreciation and basis differences	(288,416)	(235,181)
Other	(11,687)	(15,736)
Total gross deferred tax liabilities	(300,103)	(250,917)
Net accumulated deferred income taxes	$ 73,884	$ (70,010)

Upon adoption of SFAS No. 109, a valuation allowance was recorded for deferred tax assets which may not be realized, including tax carryforwards that the Company may not utilize before their expiration. The valuation allowance decreased by approximately $226.7 million in 1996, $4.5 million in 1995 and $4.4 million in 1994. The decrease in 1996 was primarily due to the Company's belief that, because of the Rate Stipulation, Reorganization, and other factors, it is more likely than not that the Company will have sufficient taxable income in the future to utilize most of the tax net operating loss ("NOL") carryforward benefits. Prior to the effective date of the Reorganization, the Predecessor Company did not assume future taxable income for the utilization of NOL carryforwards. Approximately $27.1 million of the Company's valuation allowance at December 31, 1996, if subsequently recognized as a tax benefit, would be credited directly to capital in excess of stated value in accordance with SOP 90-7.

As discussed in Note D, the Company's income tax provision has been calculated under SFAS No. 109. The Company recognized income taxes as follows (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Income tax expense (benefit):				
Federal:				
Current	$ (17,203)	$ –	$ 13,757	$ 6,320
Deferred	38,828	(2,340)	(21,703)	(21,200)
Investment tax credit amortization	–	(325)	(2,828)	(2,838)
Subtotal current operations	21,625	(2,665)	(10,774)	(17,718)
Adjustment of assets and liabilities to fair value (elimination of accumulated deferred investment tax credits)	–	(77,950)	–	–
Deferred included in reorganization items	–	(172,899)	(1,194)	(1,824)
Income tax expense on interest income during bankruptcy	–	583	4,633	2,720
Total	$ 21,625	$ (252,931)	$ (7,335)	$ (16,822)
State:				
Current	$ 278	$ 116	$ 935	$ 584
Deferred	4,767	(866)	(5,959)	(364)
Subtotal current operations	5,045	(750)	(5,024)	220
Deferred included in reorganization items	–	(17,494)	–	–
Total	$ 5,045	$ (18,244)	$ (5,024)	$ 220

The current federal income tax benefit for 1996 results primarily from the carryback of 1996 alternative minimum tax ("AMT") NOL to the 1993, 1994 and 1995 tax years and decreased by an expense for the reduction of investment tax credits ("ITC") utilized. Deferred federal income tax includes an offsetting AMT deferred expense of approximately $24.0 million and a benefit for an increase in ITC carryforward of approximately $6.8 million.

The current federal income tax expense for 1995 and 1994 results primarily from the accrual of AMT expense. The deferred federal income tax benefit recorded in 1995 and 1994 includes offsetting AMT credits of approximately $18.3 million and $8.4 million, respectively. For the years 1995 and 1994, ITC utilized of approximately $4.6 million and $2.1 million, respectively, was recorded as a reduction to current tax and included as a deferred tax expense.

Federal income tax provisions differ from amounts computed by applying the statutory rate of 35% to the book loss before federal income tax as follows (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Federal income tax expense (benefit) computed on income (loss) at statutory rate	$ 22,240	$ 45,339	$ (14,229)	$ (15,741)
Difference due to:				
ITC amortization (net of deferred taxes)	-	(211)	(1,838)	(1,845)
Nondeductible bankruptcy costs	-	3,604	5,925	3,915
Federal valuation allowance	-	(204,848)	(4,461)	(1,927)
Adjustment of assets and liabilities to fair value (elimination of accumulated deferred ITCs)	-	(77,950)	-	-
Reorganization costs (including the nontaxable extraordinary gain on the discharge of debt)	-	(27,745)	-	-
Other	(615)	8,880	7,268	(1,224)
Total federal income tax expense (benefit)	$ 21,625	$ (252,931)	$ (7,335)	$ (16,822)
Effective federal income tax rate	34.0 %	(195.3)%	18.0 %	37.4 %

The Company had approximately $733.0 million of tax NOL carryforwards, approximately $20.4 million of ITC carryforwards and approximately $9.6 million of AMT credit carryforwards as of December 31, 1996. If unused, the NOL carryforwards would expire at the end of the years 2006 through 2011, the ITC carryforwards would expire in the years 2001 through 2005 and the AMT credit carryforwards have an unlimited life.

The Reorganization and the associated implementation of fresh-start reporting gave rise to significant items of income and expense for financial reporting purposes that are not included in taxable income. These reorganization items resulted in an effective tax rate for the period from January 1 to February 11, 1996 that is significantly different than the current U.S. statutory rate of 35%.

The Bankruptcy Court entered an order on May 10, 1994 approving the terms of a settlement with the Internal Revenue Service ("IRS") covering tax periods prior to 1992, pursuant to which the Company paid approximately $6.2 million, which primarily represents interest.

J. Commitments and Contingencies

Sale/Leaseback Indemnification Obligations

Pursuant to the participation agreements and leases entered into in the sale/leaseback transactions, if the lessors incur additional tax liability or other loss as a result of federal or state tax assessments related to the sale/leaseback transactions, the lessors may have claims against the Company for indemnification. Pursuant to settlement agreements entered into between the Company and the lessors under the Palo Verde Leases, certain of the Company's indeminity obligations related to tax matters have continued after the Effective Date.

One of the lessors in the sale/leaseback transactions related to Unit 2 of Palo Verde has notified the Company that the IRS has raised issues, primarily related to ITC claims by the lessor, regarding the income tax treatment of the sale/leaseback transactions. The Company estimates that the total amount of potential claims for indemnification from all lessors related to the issues raised by the IRS could approximate $10.0 million, exclusive of any applicable interest, if the IRS prevails. This matter is at a preliminary stage and, although the Company believes the lessor has meritorious defenses to the IRS' position, the Company cannot predict the outcome of the matter or the Company's liability for any resulting claim for indemnification. The Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to this matter.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Because construction of new facilities is subject to standards imposed by environmental regulation, substantial expenditures may be required to comply with such regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforseen expenses associated with compliance could have a material, adverse effect on the future operations and financial condition of the Company.

PCB Treatment, Inc. The Company received a request from the U.S. Environmental Protection Agency ("EPA") to participate in the remediation of polychlorinated biphenyls ("PCBs") at two facilities in Kansas City, Missouri, which had been operated by PCB Treatment, Inc. ("PTI"). The Company's manifests indicate that between 1982 and 1986, the Company sent 23 shipments of PCBs or PCB-containing electric equipment ("PCB Equipment") to PTI, accounting for approximately 2 to 3%, by weight, of the PCBs and PCB Equipment received at that site by PTI. Presently, PTI has discontinued operations and the EPA has determined that PTI's abandoned facilities require remediation.

The Company and the PTI Steering Committee, which consists of the largest generators of the PCBs sent to PTI, have executed a settlement agreement. In consideration for the payment of approximately

$0.2 million, the settlement agreement excuses any further liability to the Steering Committee by the Company and indemnifies the Company for any liabilities to other parties as may be asserted in the future.

The Company may still face liability for possible deliveries of PCBs by PTI to a third site which is also subject to remedial action by the federal authorities, except to the extent that those PCBs were transferred from the first site. The Company's records do not indicate any deliveries of PCBs to this third site. Management believes the Company is unlikely to face substantial unindemnified liabilities associated with this third site.

Coal Mine Reclamation. The Company has been informed by APS that the Company's estimated financial obligation for coal mine reclamation at Four Corners is not being fully reflected in the costs for which the Company is billed. APS, the operating agent of Four Corners, is performing an analysis to establish an appropriate revised cost estimate. Based on preliminary estimates from APS and the coal provider, the Predecessor Company recorded a liability of approximately $12 million which reflects the present value of the estimated future costs of reclamation at the Effective Date to reflect its share of the coal mine reclamation obligation.

K. Litigation

Litigation with Central and South West Corporation

In May 1993, the Company entered into the Merger Agreement, pursuant to which the Company would have been acquired by CSW. In June 1995, CSW terminated the Merger Agreement. In response, the Company filed a complaint against CSW in the 205th Judicial District Court of El Paso County, Texas, alleging, among other claims, breach of contract, breach of duty of good faith and fair dealing, breach of fiduciary duty, business disparagement, tortious interference with contract and fraud in the inducement. The Company sought an unspecified amount of damages, punitive damages, attorneys' fees and costs. In June 1995, CSW filed an adversary proceeding against the Company in the Bankruptcy Court seeking the recovery of termination fees of $25 million, approximately $3.7 million in attorneys' fees and expenses that CSW claims it advanced on behalf of the Company in certain regulatory proceedings, and $25 million for the alleged violation of the Merger Agreement's no-solicitation provisions. All of the claims by both parties were tried in the Bankruptcy Court. The trial concluded on January 30, 1997, and the matter has been taken under advisement by the presiding judge. A ruling is expected in March 1997. The Company cannot predict the outcome of this litigation, but does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to the litigation between the Company and CSW. Pursuant to the terms of the Reorganization, the first $20 million in proceeds, if any, to the Company from this litigation will be distributed to the holders of preferred stock and common stock of the Predecessor Company.

Litigation with Las Cruces

Las Cruces is attempting to replace the Company as its electric service provider by acquiring, through condemnation or otherwise, the distribution assets and other facilities used to provide electric service to customers in Las Cruces. Sales to customers in Las Cruces represented approximately 7% of the

Company's operating revenues in 1996. Las Cruces has two actions pending against the Company in federal district court in New Mexico, one seeking to recover franchise fees despite the expiration of the Company's Las Cruces franchise in March 1994 and one seeking a declaratory judgment that Las Cruces can proceed with a condemnation action against the Company. In addition, the New Mexico State Legislature has recently passed a bill that would allow Las Cruces to proceed with the condemnation.

In the franchise fee action, Las Cruces is seeking the reasonable value of the Company's use, occupation and rental of Las Cruces' rights-of-way or damages for trespass and an unspecified amount of punitive damages. The Company has filed an answer denying that it has any liability or continuing payment obligation to Las Cruces regarding franchise fees or use of the Las Cruces rights-of-way, and also denies that it has committed any trespass. The Company intends to vigorously defend the lawsuit. The Company has also filed a counterclaim seeking to condemn, pursuant to statutory authority, those Las Cruces rights-of-way currently used and occupied by the Company. Las Cruces has filed an answer contesting the Company's right to proceed with such a condemnation. In August 1996, the court severed the Company's counterclaim from Las Cruces' claims for all purposes, and stayed all proceedings on the Company's counterclaim until further order of the court. The trial of Las Cruces' claims is set for May 1997. The Company has reserved in its financial statements an amount equal to the franchise fees under the expired agreement.

In April 1995, Las Cruces filed a Complaint for Declaratory Judgment against the Company in the District Court for Dona Ana County, New Mexico, seeking a declaratory judgment that Las Cruces has a right of eminent domain to condemn the electric distribution system and related facilities owned and operated by the Company within and adjacent to the city limits that provide or assist in the provision of electricity within the municipal boundaries of Las Cruces. In May 1995, the Company removed the case to the United States District Court for the District of New Mexico. In October 1995, the Company's motion for summary judgment was denied and the Court ruled that although Las Cruces lacks express statutory authority to condemn the Company's assets, such express authority is required only if the proposed condemnation would materially impair, obliterate or destroy the existing use. Following a trial on the merits, the federal magistrate issued an opinion holding that Las Cruces had not met its burden of proof that its plan would not materially impair the public use of the Company's property sought to be condemned. The magistrate also granted the Company's motion to certify to the New Mexico Supreme Court the question as to whether Las Cruces possesses the authority to condemn the Company's property for use as a municipal utility when that property is already devoted to public use. In February 1997, the New Mexico Supreme Court heard oral arguments and is expected to issue its ruling in the near future.

In March 1997, the New Mexico House of Representatives and Senate passed a bill that would give Las Cruces the authority to acquire and operate the Company's distribution system within both the city limits and a territory within five miles of the municipal boundary. If the Governor signs the bill, it would become law immediately and most likely make the issues presented to the New Mexico Supreme Court moot.

Las Cruces has taken several actions to position itself to acquire portions of the Company's distribution system and certain related facilities in the event it can proceed with condemnation. See Note C for discussion regarding Las Cruces' filing with the FERC for determination of stranded cost. In June 1994, the Las Cruces City Council approved a resolution selecting SPS to provide operation and maintenance services for the proposed Las Cruces electric distribution system, substations and associated transmission facilities and authorizing the staff of Las Cruces to negotiate a contract with SPS related to such services. In August 1994, SPS and Las Cruces entered into a fifteen-year contract granting SPS the right to provide all of the electric power and energy required by Las Cruces during the term of the contract. In addition, Las Cruces announced that, in October 1995, it sold approximately $73 million in revenue bonds to provide funding to finance the acquisition by condemnation or negotiated purchase of the Company's electrical distribution assets within and adjacent to the Las Cruces city limits.

The Company has filed a lawsuit in the Dona Ana County District Court and is pursuing a complaint simultaneously before the New Mexico Commission challenging the legality of the sale of the revenue bonds, and the New Mexico Commission is investigating the agreement between SPS and Las Cruces which would grant, in certain circumstances, Las Cruces an option to sell electric utility assets acquired through condemnation to SPS. In August 1996, the Dona Ana County District Court issued an opinion letter stating that Section 3-23-3 of the New Mexico Municipal Code is inapplicable to home rule municipalities and Las Cruces, therefore, was not required to acquire the New Mexico Commission's approval before issuing revenue bonds to acquire utility property. However, the Court did agree with the Company that the revenue bonds, in this case backed by utility revenues, are subject to the same requirements of other revenue bonds backed by gross receipts tax revenues. Therefore, if the Court's finding of the applicability of Las Cruces' home rule authority is overturned on appeal, the Company's position that the issuance of the bonds required prior approval could be upheld. The Court's order was signed and entered in November 1996. The Company has filed an appeal with the New Mexico Court of Appeals.

The Company continues to believe that it can provide lower cost electric service to customers in Las Cruces than can be achieved through a municipal takeover. Accordingly, the Company has stated its strong preference for a resolution of its differences with Las Cruces through negotiation rather than litigation and condemnation. The Company intends to vigorously pursue before the FERC its right to recover stranded costs from Las Cruces in the event Las Cruces succeeds in leaving the system.

If Las Cruces succeeds in its efforts to condemn the Company's distribution system, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court under New Mexico law. "Just compensation" is generally defined as the amount of money that would compensate the party whose property is condemned. In the Company's case, this amount would be the difference between the value of the Company's entire system prior to the taking, as compared to the value of the entire system after the taking. The Company is unable to predict the outcome of Las Cruces' litigation or its efforts to replace the Company as its electric service provider or the effects it may have on the Company's financial position, results of operations and cash flows. The Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to these matters.

Transmission Service to Mexico

In September 1996, Enron, a wholesale power marketer and one of the companies that submitted a bid to the CFE in connection with renewal of the interchange agreement for the supply of power to Ciudad Juarez, Mexico, filed a complaint against the Company with the FERC. Enron's complaint sought emergency relief and requested the FERC to direct the Company to enter into an agreement with Enron to provide Enron with firm point-to-point transmission service to the CFE under its open access transmission tariff.

In October 1996, the FERC issued an order requiring the Company to provide Enron with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction. Pursuant to an emergency application filed by Enron with the DOE, on October 30, 1996, the DOE issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties in this case. In its response to the DOE's delegation of authority, the Company has asserted that the DOE has no authority to require transmission access for delivery of power to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder in 1997, if the winning bidder is someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position that, under current law, access is not required. The FERC has docketed the Delegation and Assignment and the process is expected to continue throughout 1997.

Water Cases

San Juan River System. The Four Corners Participants are among the defendants in a suit filed by the State of New Mexico in 1975 in state district court in New Mexico against the United States of America, the City of Farmington, New Mexico, the Secretary of the Interior as Trustee for the Navajo Nation and other Indian tribes and certain other defendants (*State of New Mexico ex rel. S. E. Reynolds, New Mexico State Engineer v. United States of America, et al.*, Eleventh Judicial District Court, County of San Juan, State of New Mexico, Cause No. 75-184). The suit seeks adjudication of the water rights of the San Juan River Stream System in New Mexico, which, among other things, supplies the water used at Four Corners. The case has been inactive for many years. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Gila River System. In connection with the construction and operation of Palo Verde, APS entered into contracts with certain municipalities granting APS the right to purchase effluent for cooling purposes at Palo Verde. In 1986, a summons was served on APS that required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water in an action pending in Maricopa County Superior Court, titled *In re The General Adjudication of All Rights to Use Water in the Gila River System and Source.* Palo Verde is located within the geographic area subject to the summons and the rights of the Palo Verde Participants to the use of groundwater and effluent at Palo Verde is potentially at issue in the action. APS, as operating agent, filed claims that dispute the court's jurisdiction over the Palo Verde Participants' groundwater rights and their contractual rights to effluent relating to Palo Verde and, alternatively, seek confirmation of such rights. In December 1992, the Arizona Supreme Court heard oral argument on certain issues in this matter that are pending on interlocutory appeal. Issues important to Palo Verde Participants' claims were remanded to the trial court for further action and the trial court certified its decision for interlocutory appeal to the Arizona Supreme Court. In September 1994, the Arizona Supreme Court granted review of the June

1994 trial court decision. No trial date has been set in the matter. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Four Corners

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the "Acts"). In October 1995, the Four Corners Participants requested that the United States Secretary of the Interior resolve their dispute with the Navajo Nation regarding whether the Acts apply to operation of Four Corners. The Four Corners Participants subsequently filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that (i) the Four Corners leases and federal easements preclude the application of the Acts to the operation of Four Corners; and (ii) the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners. On October 18, 1995, the Navajo Nation and the Four Corners Participants agreed to indefinitely stay the proceedings referenced above so that the parties may attempt to resolve the dispute without litigation. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Other Legal Proceedings

The Company is a party to various other claims, legal actions and complaints. In many of these matters the Company has excess casualty liability insurance which is applicable. Based upon a review of these claims and applicable insurance coverage, management is of the opinion that none of these claims will have a material adverse effect on the operations or financial position of the Company. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the uncertainties inherent in any litigation. The Company is defending itself vigorously in all these matters.

L. Benefit Plans

Pension Plan

The Company's Retirement Income Plan (the "Retirement Plan") covers employees who have completed one year of service with the Company, are 21 years of age and work at least a minimum number of hours each year. The Retirement Plan is a qualified noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the Retirement Plan are used to pay benefit obligations under the Retirement Plan. Contributions from the Company are based on the minimum funding amounts required by the Department of Labor ("DOL") and IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

The Company's Supplemental Retirement and Survivor Income Plan for Key Employees (the "SERP") is a non-qualified, non-funded defined benefit plan which covers certain former employees of the Company. The pension cost for the SERP is based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan. As part of the Reorganization, the Company terminated the SERP with respect to all active employees resulting in a curtailment gain of approximately $2.0 million. In conjunction therewith, the Company entered into retirement agreements with ten officers who had been participants in the SERP resulting in an increase in the accumulated benefit obligation of approximately $10.2 million. This increase in the accumulated benefit obligation and the curtailment gain were recognized as reorganization items by the Predecessor Company.

Net periodic pension cost for the Retirement Plan and the SERP under SFAS No. 87, "Employers' Accounting for Pensions," is made up of the components listed below as determined using the projected unit credit actuarial cost method (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Service costs for benefits earned during the period	$ 2,148	$ 354	$ 2,011	$ 2,453
Interest costs on projected benefit obligation	5,774	749	5,157	4,896
Actual return on plan assets	(5,019)	(570)	(9,267)	378
Net amortization and deferral	842	113	6,008	(3,383)
Recognition of previously unrecognized items	–	21,738	–	–
Net periodic pension cost recognized	$ 3,745	$ 22,384	$ 3,909	$ 4,344

The assumed annual discount rates used in determining the net periodic pension cost were 7.25%, 8.50% and 7.25% for 1996, 1995 and 1994, respectively.

The pension cost includes amortization of unrecognized items. In the application of fresh-start reporting, the Company recorded the then existing unrecognized items as of February 11, 1996 in the amount of approximately $21.7 million.

The funded status of the plans and amount recognized in the Company's balance sheets at December 31, 1996 and 1995 are presented below (In thousands):

	Reorganized Company December 31, 1996		Predecessor Company December 31, 1995	
	Retirement Income Plan	SERP	Retirement Income Plan	SERP
Actuarial present value of benefit obligations:				
Vested benefit obligation	$ (57,366)	$ (18,171)	$ (55,591)	$ (9,559)
Accumulated benefit obligation	$ (59,883)	$ (18,171)	$ (57,844)	$ (11,570)
Projected benefit obligation	$ (72,951)	$ (18,171)	$ (70,958)	$ (13,441)
Plan assets at fair value	61,460	–	53,512	–
Projected benefit obligation in excess of plan assets	(11,491)	(18,171)	(17,446)	(13,441)
Unrecognized net (gain) loss from past experience	(3,520)	(1,368)	11,562	2,648
Unrecognized prior service cost	–	–	212	(407)
Unrecognized transition obligation	–	–	2,449	260
Accrued pension liability	$ (15,011)	$ (19,539)	$ (3,223)	$ (10,940)

Actuarial assumptions used in determining the actuarial present value of projected benefit obligations are as follows:

	1996	1995
Discount rate	7.50%	7.25%
Rate of increase in compensation levels	5.00%	5.00%
Expected long-term rate of return on plan assets	8.50%	8.50%

Other Postretirement Benefits

The Company provides certain health care benefits for retired employees and their eligible dependents and life insurance benefits for retired employees only. Substantially all of the Company's employees may become eligible for those benefits if they reach retirement age while working for the Company. Those benefits are accounted for under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Contributions from the Company are based on the funding amounts required by the Texas Commission in the Rate Stipulation. The assets of the Other Postretirement Benefits Plan are invested in fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

The benefit cost includes amortization of unrecognized items. In the application of fresh-start reporting, the Company recorded the then existing unrecognized items as of February 11, 1996 in the amount of approximately $52.3 million.

Net periodic postretirement benefit cost is made up of the components listed below (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Service costs for benefits earned during the period	$ 2,209	$ 279	$ 1,603	$ 2,064
Interest costs on accumulated postretirement benefit obligation	4,723	607	4,046	3,909
Actual return on plan assets	(146)	–	–	–
Amortization of transition obligations	–	263	2,363	2,172
Amortization of (gain) loss	–	60	(54)	103
Recognition of previously unrecognized items	–	52,340	–	–
Net periodic postretirement benefit cost recognized	$ 6,786	$ 53,549	$ 7,958	$ 8,248

The funded status of the plan and amount recognized in the Company's balance sheet at December 31, 1996 and 1995 are presented below (In thousands):

	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Actuarial present value of postretirement benefit obligation:		
Accumulated postretirement benefit obligation:		
Retirees	$ (29,908)	$ (32,656)
Active participants	(47,691)	(40,831)
	(77,599)	(73,487)
Plan assets at fair value	8,050	–
Accumulated postretirement benefit obligation in excess of plan assets	(69,549)	(73,487)
Unrecognized net (gain) loss from past experience	(1,764)	15,182
Unrecognized transition obligation	–	38,007
Accrued postretirement benefit liability	$ (71,313)	$ (20,298)

For measurement purposes, a 10.9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 1997; the rate was assumed to decrease gradually to 6% for 2004 and remain at that level thereafter. The health care cost trend rate assumption has a significant effect on the amounts reported. To illustrate, increasing the assumed health care cost trend rates by one percentage point in each year would increase the accumulated postretirement benefit obligation as of December 31, 1996 by $9.4 million and the aggregate of the service and interest cost components of net periodic postretirement benefit cost for the year ended December 31, 1996 by $1.3 million.

Actuarial assumptions used in determining the actuarial present value of accumulated postretirement benefit obligation are as follows:

	1996	1995
Discount rate	7.50%	7.25%
Rate of increase in compensation levels	5.00%	5.00%

M. Franchises and Significant Customers

City of El Paso Franchise

The Company's major franchise is with the City of El Paso, Texas. The franchise agreement provides an arrangement for the Company's utilization of public rights of way necessary to serve its retail customers within the City of El Paso. Under the Stipulation, the new franchise with the City of El Paso extends through August 1, 2005.

Las Cruces Franchise

The Company's franchise with Las Cruces expired in March 1994. The Company has continued to provide electric service to customers within Las Cruces and expects and intends to continue to do so. See Note K.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represented approximately $20.0 million or 3% of operating revenues in 1996. The Company signed a new contract with Ft. Bliss in August 1996, which provides that Ft. Bliss will take service from the Company through 1999, with the right thereafter to continue service on a year to year basis for two years. The Company has a contract for service to Holloman for a ten year term beginning on December 27, 1995. In August 1996, the Army advised the Company that White Sands would continue to purchase retail electric service from the Company pursuant to the retail service contract which was set to expire on December 31, 1993, but which had previously been unilaterally extended by the Army for an indefinite period, until written termination of such contract by the Army not less than one year in advance of the termination date.

Significant Customers

In 1996, 1995 and 1994, IID, a wholesale customer, accounted for approximately $41.6 million, $43.3 million and $51.1 million or 7.2%, 8.6% and 9.5%, respectively, of operating revenues. During 1996, 1995 and 1994, the Company recorded revenues pursuant to its contract with the CFE in the amount of approximately $43.9 million, $39.4 million and $42.7 million, respectively. Under the new agreement with the CFE, revenues in 1997 related to power sales to the CFE are expected to be lower than revenues recorded in 1996. See Note C.

N. Financial Instruments

SFAS No. 107, "Disclosure about Fair Value of Financial Instruments", requires the Company to disclose estimated fair values for its financial instruments. The Company has determined that cash and temporary investments, accounts receivable, long-term contract receivable, accounts payable, customer deposits, decommissioning trust funds, long-term debt, and preferred stock meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable, and customer deposits approximate fair value because of the short maturity of these items. Based on prevailing interest rates, the fair value of the long-term contract receivable approximates its carrying value. Decommissioning trust funds are carried at market value.

The fair values of the Company's long-term debt, including the current portion thereof, and preferred stock, are based on estimated market prices for similar issues and are presented in the table below:

	Carrying Amount	Estimated Fair Value
	(In thousands)	
First Mortgage Bonds	$ 827,883	$ 864,047
Pollution Control Bonds	193,135	193,135 (2)
Nuclear Fuel Financing (1)	46,630	46,630 (3)
Capitalized Lease Obligations, Copper Turbine and Other (1)	6,858	6,858 (4)
Total	$ 1,074,506	$ 1,110,670
Preferred Stock	$ 108,426	$ 119,377

(1) Includes current maturities.

(2) The interest rate on the Company's pollution control bonds is reset weekly to reflect current market rates. Consequently, the carrying value approximates fair value.

(3) The interest rate on the Company's financing and capital lease obligations for nuclear fuel purchases is reset every quarter to reflect current market rates. Consequently, the carrying value approximates fair value.

(4) Based on prevailing interest rates the estimated fair value of the Copper Turbine lease and other approximate their carrying value.

O. Selected Quarterly Financial Data (Unaudited)

	Predecessor Company	Reorganized Company				Predecessor Company			
	Period From January 1 to February 11, 1996	Period From February 12 to March 31, 1996	1996 Quarters			1995 Quarters			
			2nd	3rd	4th	1st	2nd	3rd	4th
	(In thousands except for share data)								
Operating revenues	$ 54,949	$ 69,907	$144,388	$166,656	$143,023	$112,389	$124,683	$148,177	$119,368
Operating income	5,089	14,748	34,096	44,363	27,580	11,950	17,851	31,175	5,170
Income (loss) before reorganization items (expense) and extraordinary gain on discharge of debt	(4,053)	1,689	9,500	22,770	7,960	(14,449)	(7,130)	12,258	(14,020)
Reorganization items (expense), net of income tax benefit (expense)	122,251	–	–	–	–	(1,999)	(2,472)	(658)	(4,849)
Extraordinary gain on discharge of debt	264,273 (1)	–	–	–	–	–	–	–	–
Net income (loss) applicable to common stock	382,471	137	6,603	19,793	4,898	(16,448)	(9,602)	11,600	(18,869)
Net income (loss) per common share:									
Income (loss) before extraordinary gain on discharge of debt	3.33	0.00	0.11	0.33	0.08	(0.46)	(0.27)	0.33	(0.54)
Extraordinary gain on discharge of debt	7.43 (1)	–	–	–	–	–	–	–	–
Net income (loss)	10.76	0.00	0.11	0.33	0.08	(0.46)	(0.27)	0.33	(0.54)

(1) Reflects the discharge of obligations subject to compromise for less than their recorded amounts.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

PART III and PART IV

The information set forth in Part III and Part IV has been omitted from this Annual Report to Shareholders.

Form 10-K
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 1996

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____ to ____

Commission file number 0-296

El Paso Electric Company
(Exact name of registrant as specified in its charter)

Texas	**74-0607870**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
Kayser Center, 100 North Stanton, El Paso, Texas	**79901**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(915) 543-5711**

Securities Registered Pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, No Par Value	American Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES _X_ NO ___

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Section 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. YES _X_ NO ___

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

As of March 20, 1997, the aggregate market value of the voting stock held by non-affiliates of the registrant was $309,772,975.

As of March 20, 1997, there were outstanding 60,239,236 shares of common stock, no par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the 1997 annual meeting of its shareholders are incorporated by reference into Part III of this report.

DEFINITIONS

The following abbreviations, acronyms or defined terms used in this report are defined below:

Abbreviations, Acronyms or Defined Terms	Terms
Agreed Order	Agreed Order of the Texas Commission entered August 30, 1995 implementing certain provisions of the Rate Stipulation
ANPP Participation Agreement	Arizona Nuclear Power Project Participation Agreement dated August 23, 1973, as amended
APS	Arizona Public Service Company
Bankruptcy Case	The case commenced January 8, 1992 by El Paso Electric Company in the Bankruptcy Court as Case No. 92-10148-FM
Bankruptcy Code	United States Bankruptcy Code, 11 U. S. C. §101 et seq.
Bankruptcy Court	United States Bankruptcy Court for the Western District of Texas, Austin Division
CFE	Comision Federal de Electricidad de Mexico (the national electric utility of Mexico)
Common Plant or Common Facilities	Facilities at or related to Palo Verde that are common to all three Palo Verde Units
Common Stock	Common stock, stated value $1 per share, issued by the Company in the Reorganization
Company	El Paso Electric Company
CSW	Central and South West Corporation
DOE	United States Department of Energy
Effective Date	February 12, 1996, the date the Reorganization became effective
EPE	El Paso Electric Company
FERC	Federal Energy Regulatory Commission
Four Corners	Four Corners Generating Station
FPA	Federal Power Act
Freeze Period	Ten-year period beginning August 2, 1995, during which base rates for most Texas retail customers are expected to remain frozen pursuant to the Rate Stipulation
IID	Imperial Irrigation District, an irrigation district in Southern California
KV	Kilovolt(s)
KW	Kilowatt(s)
KWH	Kilowatt-hour(s)
Merger Agreement	Agreement and Plan of Merger dated as of May 3, 1993 among the Company, CSW and CSW Sub, as amended
MW	Megawatt(s)
MWH	Megawatt-hour(s)
New Mexico Commission	New Mexico Public Utility Commission
NRC	Nuclear Regulatory Commission
OPC	Texas Office of Public Utility Counsel
Palo Verde	Palo Verde Nuclear Generating Station
Palo Verde Leases	Leases and other documents entered into in connection with a series of sale and leaseback transactions in 1986 and 1987 involving a portion of the Company's interest in Palo Verde
Palo Verde Participants	Those utilities who share in power and energy entitlements, and bear certain allocated costs, with respect to Palo Verde pursuant to the ANPP Participation Agreement
Plan	The Company's Fourth Amended Plan of Reorganization dated November 7, 1995, pursuant to which the Company emerged from bankruptcy on the Effective Date

Abbreviations, Acronyms or Defined Terms	Terms
PNM	Public Service Company of New Mexico
Predecessor Company	The Company prior to the Reorganization
Rate Stipulation	Stipulation and Settlement Agreement dated as of July 27, 1995, between the Company, the City of El Paso, OPC and most other parties to the Company's rate proceedings before the Texas Commission providing for a ten-year rate freeze and other matters
Reorganization	Reorganization and the emergence from bankruptcy by the Company pursuant to the Plan
Reorganized Company	The Company following the Reorganization
SFAS	Statement of Financial Accounting Standards
Texas Commission	Public Utility Commission of Texas
TNP	Texas-New Mexico Power Company

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PART I

Item 1. Business

General

The Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. The Company also serves wholesale customers in Texas, New Mexico, California and Mexico. The Company owns or has significant ownership interests in five electrical generating facilities providing it with a total capacity of approximately 1,500 megawatts. For the twelve months ended December 31, 1996, the Company's energy sources consisted of approximately 53% nuclear fuel, 32% natural gas, 7% coal and 8% purchased power.

The Company serves approximately 279,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and the City of Las Cruces ("Las Cruces"), New Mexico (representing approximately 56% and 7%, respectively, of the Company's revenues for the twelve months ended December 31, 1996). In addition, the Company sells electricity to wholesale customers, including Texas-New Mexico Power Company, the Imperial Irrigation District (a southern California electric power agency), and the Comision Federal de Electricidad de Mexico (the national electric utility of Mexico). Principal industrial and other large customers of the Company include steel production, copper and oil refining, garment manufacturing concerns and United States military installations, including the United States Army Air Defense Center at Fort Bliss in Texas and White Sands Missile Range and Holloman Air Force Base in New Mexico.

The Company's principal offices are located at Kayser Center, 100 North Stanton, El Paso, Texas 79901 (telephone 915-543-5711). The Company was incorporated in Texas in 1901. As of March 3, 1997, the Company had approximately 1,100 employees, approximately 30% of whom are covered by a collective bargaining agreement that expires in June 1997.

Reorganization Under Chapter 11 of the Bankruptcy Code

Plan of Reorganization

On February 12, 1996, the Company emerged from a bankruptcy proceeding which it instituted in January 1992.

As a result of the Reorganization, the Company significantly reduced its debt and simplified its capital structure. The Company's total obligations subject to compromise (including obligations related to the Palo Verde Leases, which represented $700 million of allowed claims in the Bankruptcy Case) prior to its Reorganization was $2,007 million. Under the Plan, this debt and the Palo Verde Lease obligations were extinguished and the creditors received a combination of cash and newly issued debt and equity securities of the Reorganized Company. On December 31, 1996, the capital structure of the Reorganized Company consisted of approximately $1,046 million of long-term debt, including the long-term portion of financing and capital lease obligations, approximately $108 million of redeemable preferred stock and approximately $331 million of common stock equity.

The Company has a $100 million revolving credit facility to finance nuclear fuel purchases and to provide working capital. At December 31, 1996, approximately $46.6 million of this revolving credit facility had been drawn to finance nuclear fuel, of which approximately $20.2 million is included in the long-term debt described above. Under the Plan, all of the Predecessor Company's common and preferred stock was canceled and the holders of such securities received approximately 15% of the Reorganized Company's Common Stock and the right to receive certain litigation recoveries, if any.

In addition, on the Effective Date, the Palo Verde Leases were terminated and the Company reacquired such interests. The Company has agreed to indemnify certain parties to the Palo Verde Lease transactions against certain possible tax liabilities.

The Company's Common Stock began trading on the American Stock Exchange on February 16, 1996 under the symbol "EE."

Rate Stipulation

The Agreed Order entered on August 30, 1995 by the Texas Commission became effective on the Effective Date. The Agreed Order implemented the Rate Stipulation, dated July 27, 1995, among the Company and substantially all of the other parties to a rate proceeding in Texas. Among other things, under the Rate Stipulation, (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for ten years beginning August 2, 1995; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; and (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales. See "Regulation – Texas Rate Matters – Rate Stipulation and Agreed Order."

Accounting Treatment

The Reorganization had significant impacts on the Company's financial statements, including the creation of a new reporting entity upon emergence from bankruptcy through the application of fresh-start reporting pursuant to Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" ("SOP 90-7"). Accordingly, the Company's post-Reorganization financial statements, which reflect the application of fresh-start reporting, have not been prepared on a consistent basis with the pre-Reorganization financial statements and are not comparable in all respects to the financial statements prior to the Reorganization. The implementation of the Rate Stipulation and fresh-start reporting resulted in (i) decreased operation expense and increased depreciation expense due to the reacquisition of previously sold and leased back generation facilities and due to accelerated depreciation expense on a portion of the reorganization value assigned to certain plant assets; (ii) increased interest expense due to the changes in the Company's capital structure; and (iii) increased operating revenues related to a rate increase in the Company's Texas jurisdiction. For accounting purposes, the inception date of the Reorganized Company is deemed to be February 12, 1996. A vertical line is shown in the financial statements to separate the Reorganized Company from the Predecessor Company since the financial statements have not been prepared on a consistent basis of accounting.

Facilities

As described below, the Company currently has a net installed generating capacity of approximately 1,500 MW, consisting of an entitlement of 600 MW from Palo Verde Units 1, 2 and 3, 482 MW at its Newman Power Station, 246 MW at its Rio Grande Power Station, an entitlement of 104 MW from Four Corners Units 4 and 5, and 68 MW at its Copper Power Station.

Palo Verde Station

The Company owns a 15.8% interest in each of the three 1,270 MW nuclear generating units and Common Plant at Palo Verde, located west of Phoenix, Arizona. The Palo Verde Participants include the Company and six other utilities: APS, Southern California Edison Company ("SCE"), PNM, Southern California Public Power Authority, Salt River Project Agricultural Improvement and Power District ("SRP") and the Los Angeles Department of Water and Power. APS serves as operating agent for Palo Verde.

The NRC has granted facility operating licenses and full power operating licenses for all three units at Palo Verde for terms of forty years each. In addition, the Company is separately licensed by the NRC to own its proportionate share of Palo Verde.

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units and each Palo Verde Participant is required to fund its proportionate share of fuel, other operation, maintenance and capital costs. The Company's total monthly share of these costs was approximately $6.9 million in 1996. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

Decommissioning. Pursuant to the ANPP Participation Agreement, as well as pursuant to applicable law, the Company is required to fund its share of the estimated costs to decommission Palo Verde over the estimated service life of forty years. The Company's funding requirements are derived from periodic engineering cost estimates.

In December 1995, the Palo Verde Participants approved a study by an outside engineering firm of the cost of decommissioning Palo Verde. The 1995 study determined that the Company will have to fund approximately $229 million (stated in 1995 dollars) to cover its share of such costs. The 1995 study assumes that (i) maintenance expense for spent fuel storage will be incurred for ten years after the shutdown of the last unit (estimated to be in 2024) rather than the approximately 30 years utilized in a 1993 study; (ii) a national interim spent fuel storage facility will be available; and (iii) as a result of such national spent fuel storage facility, the amount of spent fuel stored on-site is reduced from all spent fuel assemblies to the final core plus fuel assemblies from approximately three refuelings. See "Energy Sources – Nuclear Fuel – Spent Fuel Storage."

Cost estimates for decommissioning have increased with each study, although the 1995 cost estimate is comparable to the previous cost estimate from a 1993 study (which determined that the Company would have to fund approximately $221 million, stated in 1993 dollars). The 1993 study was based on different assumptions, primarily related to the decommissioning of spent fuel. The 1993 cost estimate included an estimated cost of approximately $50 million related to on-site spent fuel storage facilities, while the 1995 study includes an estimated cost of approximately $13 million related to spent fuel. This difference in estimates is primarily due to the different timing assumptions discussed above. The 1993 estimate reflected an 84% increase from the previous estimate made in 1989, primarily due to an increase in the estimated costs associated with the permanent burial of low-level radioactive waste due to the uncertainty surrounding the availability and cost of low-level radioactive waste repositories, as discussed below.

Although the 1995 study is based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste may increase significantly. See "Disposal of Low-Level Radioactive Waste" below.

The rate freeze under the Rate Stipulation would preclude the Company from seeking a rate increase in Texas during the Freeze Period to recover increases in decommissioning cost estimates. Additionally, there can be no assurance that the Company could increase its rates in any of its other jurisdictions to recover such increased costs. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operational Prospects and Challenges."

Steam Generators. Palo Verde has experienced degradation in the steam generator tubes of each unit. The degradation includes axial tube cracking in the upper regions of the two steam generators in Unit 2 and, to a lesser degree, in Units 1 and 3. This form of steam generator tube degradation has recently been seen at other U.S. nuclear generating stations. The units also have experienced circumferential cracking at the tube sheet, a more common type of tube cracking. The axial tube cracking was discovered following a steam generator tube rupture in Unit 2 in March 1993. Since that time, APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS has stated that it believes its remedial actions have slowed the rate of tube degradation.

Each of the Palo Verde units has been inspected during regularly scheduled refueling outages and mid-cycle inspection outages. If tube cracks are detected during an inspection, the affected tubes are taken out of service by plugging. This may impair the performance of a unit if sufficient numbers of steam generator tubes are affected.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during outages of the Palo Verde units. In August 1995, APS announced that its ongoing analyses indicated that it will be economically desirable to replace the Unit 2 steam generators, which have been the most affected by tube cracking, in four to nine years. APS further stated that it expects replacement of the steam generators will be performed in conjunction with a normal refueling outage to limit incremental outage time. APS also has stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated life of 40 years (to 2025 and 2027, respectively). APS will continue to assess these steam generators periodically.

Steam generator replacement could be done through new steam generators manufactured for Palo Verde or through the purchase of existing steam generators that are compatible with Palo Verde's design. The Company believes replacement of the steam generators would require the unanimous approval of the Palo Verde Participants. The Company has not yet completed its analysis of the economic feasibility of steam generator replacement, or other options that may be available in connection with the operation of Unit 2. Also, the Company cannot predict whether it or other Palo Verde Participants will agree to replace the Unit 2 steam generators. The Company expects that if the steam generators in Unit 2 are replaced, most of such costs would be incurred between 1998 and 2005. The Company's portion of total costs associated with replacement of the Unit 2 steam generators, including replacement power costs, is currently estimated not to exceed $30 million.

The Rate Stipulation, however, precludes the Company from seeking a rate increase in Texas during the Freeze Period to recover capital costs associated with such replacement should it be necessary. It is uncertain whether the costs associated with replacing the Unit 2 steam generators would be approved by the New Mexico Commission and included in the Company's rate base in New Mexico. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations – Operational Prospects and Challenges."

Disposal of Low-Level Radioactive Waste. Congress has established requirements for the disposal of radioactive waste by each state generated within its borders. Arizona, California, North Dakota and South Dakota have entered into a compact (the "Southwestern Compact") for the disposal of low-level radioactive waste. California will act as the first host state of the Southwestern Compact, and Arizona will serve as the second host state. The construction and opening of the California low-level radioactive waste disposal site in Ward Valley has been delayed due to extensive public hearings, disputes over environmental issues and review of technical issues related to the proposed site. Despite being licensed by the State of California, the Department of the Interior has not transferred the land to the state. Following a report by the National Academy of Sciences, the Department of the Interior announced that if certain environmental conditions were implemented prior to the transfer, it was prepared to convey the land. The State of California is attempting to obtain the land through the court system without the imposition of these environmental restrictions. Although Palo Verde is estimated to undergo decommissioning during the period in which Arizona will act as host for the Southwestern Compact, the opposition, delays, uncertainty and costs experienced in California demonstrate possible roadblocks that may be encountered in the future when Arizona seeks to open its own waste repository.

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability of $200 million under federal law in the form of primary liability insurance provided by commercial insurance carriers. Additionally, the Company participates in an industry-wide retrospective assessment program, under which industry participants would be required to pay an assessment to cover any loss in excess of $200 million. The maximum assessment per reactor for each nuclear incident is approximately $79.2 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential assessment per incident is approximately $37.6 million, with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.7 billion, a substantial portion of the proceeds of which must first be applied to stabilization and decontamination. Finally, the Company has insurance against a portion of any increased cost of generation or purchased power which may result from the accidental outage of any of the three Palo Verde units if the outage exceeds 21 weeks.

Newman Power Station

The Company's Newman Power Station, located in El Paso, Texas, consists of four generating units with an aggregate capacity of 482 MW. The units operate primarily on natural gas, but are also capable of operating on fuel oil.

Rio Grande Power Station

The Company's Rio Grande Power Station, located in Sunland Park, New Mexico, adjacent to El Paso, Texas, consists of three steam-electric generating units with an aggregate capacity of 246 MW. The units operate primarily on natural gas, but are also capable of operating on fuel oil.

Four Corners Station

The Company owns an undivided 7% interest in Units 4 and 5 at Four Corners, located in northwestern New Mexico. The two coal-fired generating units each have a generating capacity of 739 MW. The Company shares power entitlements and certain allocated costs of the two units with APS (the Four Corners operating agent) and the other participants.

Four Corners is located on land held under easements from the federal government and a lease from the Navajo Nation that expires in 2016. Certain of the facilities associated with Four Corners, including transmission lines and almost all of the contracted coal sources, are also located on Navajo land. Units 4 and 5 are located adjacent to a surface-mined supply of coal.

Copper Power Station

The Company's Copper Power Station, located in El Paso, Texas, consists of a 68 MW combustion turbine used primarily to meet peak demands. The unit operates primarily on natural gas, but is also capable of operating on fuel oil. The combustion turbine and other generation equipment at the station were sold and leased-back by the Company in 1980 pursuant to a twenty-year lease with an option to renew for up to a seven-year period.

Transmission and Distribution Lines and Agreements

The Company owns or has significant ownership interests in four major transmission lines and owns the distribution network within its retail service area. The Company is also a party to various transmission and power exchange agreements that, together with its owned transmission lines, enable the Company to obtain its energy entitlements from its remote generation at Palo Verde and Four Corners.

Springerville-Diablo Line. The Company owns a 310-mile, 345 KV transmission line from Tucson Electric Power Company's ("TEP") Springerville Generating Plant near Springerville, Arizona to the Luna Substation near Deming, New Mexico, and to the Diablo Substation near Sunland Park, New Mexico, providing an interconnection with TEP for delivery of the Company's generation entitlements from Palo Verde and, if necessary, Four Corners.

Arroyo-West Mesa Line. The Company owns a 202-mile, 345 KV transmission line from the Arroyo Substation located near Las Cruces, New Mexico to PNM's West Mesa Substation located near Albuquerque, New Mexico. This is the delivery point for the Company's generation entitlement from Four

Corners, which power is transmitted to the West Mesa Substation over approximately 150 miles of transmission lines owned by PNM. This transmission line also carries power from the region to the west and north of Four Corners, where the Company has a major interconnection with the other Four Corners Participants.

Greenlee-Newman Line. The Company owns undivided interests in a 196-mile, 345 KV transmission line from the Newman Power Station to TEP's Greenlee Substation in Arizona. This line provides an interconnection with TEP for delivery of the Company's entitlements from Palo Verde and, if necessary, Four Corners.

AMRAD-Eddy County Line. The Company owns an undivided 66.7% interest in a 125-mile, 345 KV transmission line from the AMRAD Substation near Oro Grande, New Mexico to the Company's and TNP's high voltage direct current terminal at the Eddy County substation near Artesia, New Mexico. This terminal enables the Company to connect its transmission system to that of Southwestern Public Service Company ("SPS"), providing the Company with access to power markets to the east.

Issues Regarding Operation of Transmission System

The Company experienced three system outages between September 19, 1995 and October 21, 1995 and a fourth system outage on March 29, 1996. The four outages were caused by different combinations of factors. The first three outages involved faults on one of the Company's transmission lines, followed by relay failures that resulted in the loss of a second Company transmission line and the subsequent inability of the Company's load shedding programs to prevent general system instability. The fourth outage was caused by a fault on a neighboring utility's transmission line followed by relay failures on the Company's transmission system that caused the loss of two of the Company's transmission lines. Although the Company was able to stabilize its system for a brief period of time following the loss of the two lines through a controlled load-reduction scheme, a system outage occurred after a third Company line tripped out of service.

In response to the outages, the Company has undertaken numerous remedial measures, including the replacement of certain relay equipment, the reconfiguration of structures that support certain high voltage wires and the installation of two new load shedding systems, to lessen the likelihood that future transmission faults will cause general system instability and widespread outages. While performing these measures between mid-November 1995 and early January 1996, the Company materially reduced the amount of power imported into the El Paso load center in order to reduce stress on the system in the event of a fault on these lines. Operation in this mode resulted in increased operating costs of approximately $2.3 million due to the use of higher cost power from local generating plants and the necessity of purchasing power from other utilities to supply the Company's customers. While the Company can operate in this mode during cool weather months when demand is low, the Company requires its full allocation of power from its remote generating sources to meet the normal demands of customers and contractual commitments to Mexico in the warmer months.

The Company believes that its remedial efforts have solved the outage problem, and the Company has continued to import normal amounts of power over its transmission lines since January 1996. If the Company experiences further difficulties with its system, it could be required to adopt costly operating procedures until appropriate remedial efforts are implemented, and the Company might not be able to deliver sufficient power to meets its contractual obligations or to fulfill its statutory obligation to serve customers. In addition, the Texas and the New Mexico Commissions, which have monitored the

Company's efforts to address the outages, could impose penalties or other sanctions or deny the Company recovery of certain fuel and/or purchased power costs related to the Company's decision to reduce power imports during the period referenced above. The Company's capital expenditure budget does not provide for major expenditures relating to the transmission system, and certain of the Company's debt obligations restrict or prohibit major unanticipated capital expenditures. In addition, the cost of constructing new transmission facilities could not be charged to Texas retail customers under the Rate Stipulation, and the Company cannot assure that it would be able to charge any of its customers outside of Texas for such construction costs.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Because construction of new facilities is subject to standards imposed by environmental regulation, substantial expenditures may be required to comply with such regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforseen expenses associated with compliance could have a material adverse effect on the future operations and financial condition of the Company. See Part II, Item 8, "Financial Statements and Supplementary Data – Note J of Notes to Financial Statements."

PCB Treatment, Inc. The Company received a request from the U.S. Environmental Protection Agency ("EPA") to participate in the remediation of polychlorinated biphenyls ("PCBs") at two facilities in Kansas City, Missouri, which had been operated by PCB Treatment, Inc. ("PTI"). The Company's manifests indicate that between 1982 and 1986, the Company sent 23 shipments of PCBs or PCB-containing electric equipment ("PCB Equipment") to PTI, accounting for approximately 2 to 3%, by weight, of the PCBs and PCB Equipment received at that site by PTI. Presently, PTI has discontinued operations and the EPA has determined that PTI's abandoned facilities require remediation.

The Company and the PTI Steering Committee, which consists of the largest generators of the PCBs sent to PTI, have executed a settlement agreement. In consideration for the payment of approximately $0.2 million, the settlement agreement excuses any further liability to the Steering Committee by the Company and indemnifies the Company for any liabilities to other parties as may be asserted in the future.

The Company may still face liability for possible deliveries of PCBs by PTI to a third site which is also subject to remedial action by the federal authorities, except to the extent that those PCBs were transferred from the first site. The Company's records do not indicate any deliveries of PCBs to this third site. Management believes the Company is unlikely to face substantial unindemnified liabilities associated with this third site.

Coal Mine Reclamation. The Company has been informed by APS that the Company's estimated financial obligation for coal mine reclamation at Four Corners is not being fully reflected in the costs for which the Company is billed. APS, the operating agent of Four Corners, is performing an analysis to establish an appropriate revised cost estimate. Based on preliminary estimates from APS and the coal provider, the Predecessor Company recorded a liability of approximately $12 million which reflects the present value of the estimated future costs of reclamation at the Effective Date to reflect its share of the coal mine reclamation obligation.

Construction Program

The Company has no current plans to construct any new generating facilities through at least 2004. Utility construction expenditures reflected in the table below consist primarily of expanding and updating the electric transmission and distribution systems and the cost of improvements at Palo Verde. The Company's estimated cash construction costs for 1997 through 2000 are approximately $206 million. Actual costs may vary from the construction program estimates set forth below. Such estimates are reviewed and updated periodically to reflect changed conditions.

By Year (1) (In millions)		By Function (In millions)	
1997	$ 50	Production (1)	$ 53
1998	52	Transmission	20
1999	50	Distribution	102
2000	54	General	31
Total	$ 206	Total	$ 206

(1) Does not include acquisition costs for nuclear fuel. See "Energy Sources – Nuclear Fuel."

Energy Sources

General

The following table summarizes the percentage contribution of nuclear, natural gas, coal, and purchased power to the total KWH energy mix of the Company.

Power Source	Years Ended December 31, 1996	1995	1994
Nuclear	53%	53%	45%
Natural Gas	32	30	32
Coal	7	9	9
Purchased Power	8	8	14
Total	100%	100%	100%

Fuel and purchased power costs are generally passed through directly to customers in Texas and New Mexico pursuant to currently applicable regulations. Historical fuel costs and revenues are reconciled periodically in proceedings before the appropriate commission to establish the applicable fuel rate to be charged customers and to determine whether a refund or surcharge based on such historical costs and revenues is necessary. See "Regulation – Texas Rate Matters – Fuel," " – New Mexico Rate Matters – Fuel" and Part II, Item 8, "Financial Statements and Supplementary Data – Note C of Notes to Financial Statements."

Nuclear Fuel

The Palo Verde Participants have contracts for uranium concentrate which should be sufficient to meet Palo Verde's operational requirements through at least 2000. Spot purchases in the uranium market will also be made, as appropriate. The Palo Verde Participants have contracted for up to 100% of conversion services required through 2000. The Palo Verde Participants have an enrichment services contract with the United States Enrichment Corporation ("USEC") which obligates USEC to furnish the enrichment services required for the operation of the three Palo Verde units through 2002, with an option for five additional years. A new contract provides fuel assembly fabrication services for each Palo Verde unit through 2016.

Spent Fuel Storage. The spent fuel storage facilities at Palo Verde have sufficient capacity to store all fuel expected to be discharged from normal operation of all of the Palo Verde units through at least 1999. If necessary, more spaces in the existing fuel pool may be approved for use by the NRC which would extend storage capacity through 2001, or, if more economical, alternative storage facilities can be constructed on-site.

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987, the DOE is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. In November 1989, the DOE reported that such disposal facilities will not be in operation until 2010. Subsequent judicial decisions require the DOE to start disposing of spent nuclear fuel no later than January 31, 1998, although the DOE has told APS that it will not meet this deadline. As a result, under the DOE's current criteria for shipping allocation rights, it is estimated that Palo Verde could not ship spent fuel to the DOE permanent disposal facility until approximately 2025. APS has indicated that alternative interim spent fuel storage methods will be available on-site or off-site for use by Palo Verde to allow its continued operation and to store spent fuel safely until shipments to the DOE's permanent disposal facility begin. The Texas Commission is currently evaluating what, if any, action it should take with regard to payments made by the Company to the DOE for funding of the DOE's obligation to start accepting spent nuclear fuel by January 31, 1998.

Nuclear Fuel Financing. Pursuant to the ANPP Participation Agreement, the Company has an undivided interest in nuclear fuel purchased in connection with Palo Verde. On the Effective Date, the Company and Texas Commerce Bank, as trustee, entered into a $100 million credit facility with Chemical Bank that includes a portion for working capital requirements and up to $60 million for the financing of nuclear fuel. At December 31, 1996, approximately $46.6 million had been drawn to finance nuclear fuel. The Company also entered into a purchase contract with the trustee related to the financing of nuclear fuel purchases. Under the terms of the documents related to the nuclear fuel financing, the trust borrows under the credit facility amounts sufficient to purchase and prepare nuclear fuel for use. The Company is obligated to repay borrowings by the trustee under the facility, which obligation is secured by Collateral Series Bonds, and is required to make quarterly payments to the trust for the heat energy produced by the nuclear fuel and used by the Company. For financial reporting purposes, the Company reports the assets and liabilities of the trust as its own.

Natural Gas

In 1996, the Company's natural gas requirements at the Rio Grande Power Station were met solely with spot natural gas purchases from various suppliers. Interstate gas is delivered under a firm ten year transportation agreement, which expires in 2001. Based on the current availability of economic and reliable spot natural gas, the Company anticipates it will continue to purchase spot natural gas for the Rio Grande Power Station for the near term. To complement the spot purchases, the Company has entered into a one-year gas supply contract with Cook Inlet for 1997. For the long term, the Company will evaluate the availability of spot natural gas versus other supplies in obtaining a reliable and economical supply for the Rio Grande Power Station.

In 1996, the natural gas requirements for the Newman and Copper Power Stations were supplied and transported pursuant to an intrastate natural gas contract which expired December 31, 1996. The Company has an agreement with KN-Energy to supply gas to the Newman and Copper Power Stations beginning in 1997 through 2001. To augment this contract, the Company procured a second natural gas supply agreement with U.S. Gas Transportation, Inc., which runs through 2001.

Coal

APS, as operating agent for Four Corners, purchases Four Corners' coal requirements from a supplier with a long-term lease of coal reserves owned by the Navajo Nation. Management believes that Four Corners has sufficient reserves of coal to meet the plant's operational requirements for its useful life.

Purchased Power

To supplement its own generation, the Company has a firm power purchase agreement with SPS for a minimum of 35 MW for 1997.

Operating Statistics

	December 31,		
	1996 (A)	1995 (B)	1994 (B)
Operating revenues (In thousands):			
Base revenues:			
Retail:			
Residential	$ 141,719	$ 128,295	$ 129,869
Commercial and industrial, small	138,910	128,715	126,450
Commercial and industrial, large	43,483	40,870	39,754
Sales to public authorities	65,534	59,613	59,811
Total retail	389,646	357,493	355,884
Wholesale sales for resale	71,254	74,557	75,750
Total base revenues	460,900	432,050	431,634
Fuel revenues and economy sales	114,042	68,823	101,076
Other	3,981	3,744	4,050
Total operating revenues	$ 578,923	$ 504,617	$ 536,760
Number of customers (End of year):			
Residential	250,209	245,245	240,368
Commercial and industrial, small	25,304	24,615	23,857
Commercial and industrial, large	102	89	80
Other	3,711	3,674	3,470
Total	279,326	273,623	267,775
Average annual use and revenue per residential customer:			
KWH	6,238	6,057	6,313
Revenue	$ 661.04	$ 578.88	$ 644.82
Average revenue per KWH:			
Residential	10.60 ¢	9.56 ¢	10.21 ¢
Commercial and industrial, small	9.21	8.15	8.88
Commercial and industrial, large	4.85	4.34	5.01
Energy supplied, net, KWH (In thousands):			
Generated	7,920,675	7,439,404	7,018,423
Purchased and interchanged	711,791	584,853	1,051,251
Total	8,632,466	8,024,257	8,069,674
Energy sales, KWH (In thousands):			
Retail:			
Residential	1,545,274	1,473,349	1,500,426
Commercial and industrial, small	1,779,986	1,754,176	1,721,736
Commercial and industrial, large	1,216,941	1,121,329	1,092,028
Sales to public authorities	1,110,706	1,068,048	1,081,850
	5,652,907	5,416,902	5,396,040
Wholesale:			
Sales for resale	1,753,553	1,646,357	1,925,671
Economy sales	757,999	538,102	320,026
Total sales	8,164,459	7,601,361	7,641,737
Losses and company use	468,007	422,896	427,937
Total	8,632,466	8,024,257	8,069,674
Native system:			
Peak load, KW	1,105,000	1,088,000	1,093,000
Net generating capacity for peak, KW	1,500,000	1,500,000	1,497,000
Load factor	63.4 %	61.6 %	61.1 %
Total system:			
Peak load, KW	1,387,000	1,374,000	1,365,000
Net generating capacity for peak, KW	1,500,000	1,500,000	1,497,000
Load factor	64.2 %	62.0 %	63.7 %

(A) Financial data is based on the combined results for the Predecessor Company for the period January 1, 1996 to February 11, 1996 and the Reorganized Company for the period February 12, 1996 to December 31, 1996.

(B) Predecessor Company.

Texas Rate Matters

The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services in Texas and jurisdiction over certain activities of the Company.

Rate Stipulation and Agreed Order. The Company's rates for its Texas jurisdictional customers are governed by the Agreed Order, which became effective on the Effective Date. The Agreed Order implemented certain provisions of the Rate Stipulation and set rates consistent with the Rate Stipulation. Among other things, under the Rate Stipulation: (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for the Freeze Period; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) the Company's reacquisition of the Palo Verde leased assets is deemed to be in the public interest; (vi) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vii) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

Neither the Rate Stipulation nor the Agreed Order deprives the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined in the Agreed Order that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Rate Stipulation (other than the General Counsel, OPC and the State of Texas) agreed not to seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Rate Stipulation retain all rights provided in the Rate Stipulation, their rights to participate as a party in any proceeding related to the merger, as well as the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings. See "Recent Changes in Utility Regulation."

Fuel. The Company must periodically reconcile its Texas fuel costs pursuant to Texas Commission rules. The Company has not filed a reconciliation, which must contain not less than twelve months nor more than thirty-six months of reconcilable data for any period since June 1995. In a reconciliation, revenues that the Company collected from Texas customers under its fixed fuel factor are reconciled with the expenses for fuel and purchased power actually incurred by the Company for the period covered by the reconciliation. Differences between revenues collected and expenses incurred are subject to a refund to customers (in the case of an overrecovery of fuel costs) or surcharge (in the case of an underrecovery of fuel costs). The Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the recovery of expenses on the basis of unreasonable or improper fuel and purchased power costs.

Higher natural gas prices began in December 1996 and continued in the first quarter of 1997. These higher natural gas prices will increase the Company's underrecovered fuel costs, which will be reviewed in the next Texas fuel reconciliation.

Palo Verde Performance Standards. The Texas Commission has established performance standards for the operation of Palo Verde, pursuant to which Palo Verde is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. There are five performance bands based around a target capacity factor of 70%. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission could reconsider the rate treatment of Palo Verde, regardless of the provisions of the Rate Stipulation. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Based upon the formula for calculating the performance standards in Texas, the Company does not believe a performance penalty will be assessed for the year ended December 31, 1996.

New Mexico Rate Matters

The New Mexico Commission has jurisdiction over the Company's rates and services in New Mexico and jurisdiction over certain activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. Current base rates in New Mexico were established in 1990 and have not increased. The Company does not have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation.

Pending Rate Case. In October 1996, the New Mexico Commission issued an order in Case No. 2722, requiring the Company to answer certain ratepayer complaints and to file a rate filing package, including cost of service data and supporting testimony. On March 3, 1997, the Company filed all of the rate filing package data required by the Commission's order with the Commission. Although the Company's filing demonstrates a revenue deficiency of approximately $8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Fuel. The Company is required to file an annual fuel report and an annual Palo Verde performance standards report, discussed below, with the New Mexico Commission by January 31 of each year for the preceding calendar year. The Company requested and received two extensions of time and filed these reports on March 24, 1997. The Company's filing reflects a significant increase in the monthly fuel charge to be effective with bills rendered on or after May 1, 1997. This increase is necessary because of significant increases in the spot price of natural gas which have caused the Company to underrecover its fuel costs in New Mexico by approximately $2.0 million for the year ended December 31, 1996. The recovery of this amount, coupled with projected higher gas costs for 1997, results in an increase in the proposed 1997 fuel factor of approximately 50% over the present factor. There can be no assurance that the Commission will accept the Company's proposed fuel factor. As in Texas, interested parties are allowed to intervene and challenge the recoverability of expenses as unreasonable or imprudent. Any significant disallowance of recovery could have a material adverse effect on the Company's financial results.

Palo Verde Performance Standards. The New Mexico Commission has established performance standards for the operation of Palo Verde, pursuant to which the entire Palo Verde station is evaluated annually to determine if its achieved capacity factor allows the Company to claim a credit or subjects the Company to a penalty. Because Unit 3 is not included in the Company's New Mexico rate base, any penalty or credit calculated on a total station basis is limited to two-thirds of such penalty or credit. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the annual capacity factor is 35% or less, the New Mexico Commission is required to initiate a proceeding to reconsider the rate base treatment of Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. For the year ended December 31, 1996, the Palo Verde station capacity factor was 86.20%. This capacity factor resulted in the Company's entitlement to a credit. However, the Company is voluntarily foregoing collection of this credit to partially mitigate the increase in the proposed New Mexico fuel factor, discussed above.

Federal Regulatory Matters

Federal Energy Regulatory Commission. The Company is subject to regulation by the FERC in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

The Company has a long-term firm power sales agreement with IID providing for the sale of 100 MW of firm capacity and 50 MW of contingent capacity through April 2002. The agreement generally provides for level sales prices over the life of the agreement. The Company has a firm power sales agreement with TNP, providing for sales to TNP in the minimum amount of 25 MW through 2002. Sales prices are essentially level for the remaining life of the agreement. Rate tariffs currently applicable to IID and TNP contain fuel and purchased power cost adjustment provisions designed to recover the Company's fuel and purchased power costs.

In July 1996, the Company filed its open access transmission tariffs (Docket No. OA96-200-000) in compliance with Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* ("Order No. 888"), covering network and point-to-point transmission services and the six specifically required ancillary services. Several parties, including Las Cruces, other utilities and several wholesale power marketers intervened and filed protests to the Company's tariffs. Issues raised by the intervenors included rates and the terms and conditions of the Company's tariffs, including the treatment and costs related to certain facilities making access to the CFE more available to parties other than the Company. In February 1997, the Company entered into a stipulated agreement among the various parties settling all issues related to Docket No. OA96-200-000. Under the settlement the Company will provide transmission service, to the extent transmission capacity is available, to any party for firm or interruptible service to the CFE until the earlier of the end of 1998 or the date the FERC rules on the complaint filed by Enron. See Item 3, "Legal Proceedings – Transmission Service to Mexico."

In December 1996, Las Cruces filed a request at the FERC for a determination that Las Cruces would have no stranded cost obligation to the Company in the event the city leaves the Company's system and operates its own municipal utility. The Company calculated Las Cruces' stranded cost obligation to be approximately $234 million. The FERC is expected to establish a procedural schedule for discovery and hearings in this matter. The Company is unable to predict the outcome of this proceeding or the impact it may have on the Company. See Item 3, "Legal Proceedings – Litigation with Las Cruces."

Also in December 1996, SPS filed a request for the issuance of an order by the FERC requiring the Company to accept as a "completed application" for service under the Company's open access transmission tariff a September 1996 request by SPS for service that may be needed for SPS to deliver electricity to a newly-formed Las Cruces municipal electric system. The Company stated in response to that request that SPS had failed to provide certain information required to be submitted by persons seeking service under its open access transmission tariff. The Company has asked that the proceedings initiated by Las Cruces and by SPS, respectively, be consolidated. Both matters are currently pending before the FERC.

Department of Energy. The DOE traditionally regulates the Company's exports of power to the CFE in Mexico pursuant to a license granted by the DOE and a presidential permit. In addition, the DOE is authorized to assess operators of nuclear generating facilities for a share of the costs of decommissioning the DOE uranium enrichment facilities.

In October 1996, the FERC issued an order requiring the Company to provide Enron Power Marketing, Inc., a wholesale power marketer, with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction.

Promptly after the issuance of the FERC order, Enron asked the DOE to exercise its authority over Presidential Permits relating to construction of border-crossing transmission facilities and over export authorizations issued to the Company and to Enron to require transmission access for delivery of electricity to the CFE in Mexico. Pursuant to Enron's request, the DOE, on October 30, 1996, issued a Notice and Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties with respect to Presidential Permits and export authorizations issued to the Company. The Company has filed responses to Enron's request at both the FERC and the DOE in which it has asserted that the DOE has no authority to require transmission of electric energy for delivery to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder during 1997, if someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position, which remains that under the current law the provision of such access is not required. Neither the FERC nor the DOE has taken any final action on this matter.

Nuclear Regulatory Commission. The NRC has jurisdiction over the Company's licenses for Palo Verde and regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards and has authority to conduct environmental reviews pursuant to the National Environmental Policy Act.

Other Wholesale Customers

The primary term of the Company's previous five year sales agreement for firm capacity and associated energy to the CFE terminated December 31, 1996. In September 1996, the CFE issued a request for proposals for replacement power for 1997. The Company submitted a bid and was ultimately selected by the CFE to provide varying amounts of power during 1997 ranging from 120 to 200 MW. Since the CFE load provided by the Company will be isolated from the rest of the CFE system, the Company is also providing the CFE with the flexibility to increase its power deliveries up to 5% above its monthly contract capacity level in order to meet its customer power requirements. The price is stable throughout the term of the agreement and includes charges for capacity and energy as well as transmission and any required ancillary services. Under the new agreement with the CFE, revenues in 1997 related to power sales to the CFE are expected to be lower than revenues recorded in 1996. The agreement requires payment in United States dollars. See Item 3, "Legal Proceedings – Transmission Service to Mexico" and Part II, Item 8, "Financial Statements and Supplementary Data – Note M of Notes to Financial Statements."

Recent Changes in Utility Regulation

General. The electric utility industry faces increasing pressure to become more competitive as legislative, regulatory, economic and technological changes occur. Federal legislation, as well as legislative and regulatory initiatives in various states and proposed initiatives in Texas and New Mexico, encourages competition in the Company's service area for electricity generation among electric utility and non-utility power producers. Together with increasing customer demand for lower-priced electricity and other energy services, these measures have accelerated the industry's movement toward more competitive pricing and cost structures. Such competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets, as well as the cost of operating these assets. This issue is particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flows and financial condition of the Company, or that the Company will be able to sustain retail rates at the levels established by the Rate Stipulation during the Freeze Period.

Of particular importance to the Company is the issue of ultimate recoverability of costs previously found by regulatory authorities to be reasonable and prudent, but which at the same time are higher than would be recovered under immediate, full competition (i.e., stranded costs). Across the industry, as well as at the state level, there is much discussion and debate on this issue. At this time, there appears to be no clear solution. At the federal level, the FERC has announced, through a formal rulemaking, its intention to allow 100% recovery of all legitimate verifiable stranded costs attributable to FERC jurisdictional customers. Texas and New Mexico are engaged in various activities, at the commission and legislative level, which are attempting to address the issue of stranded cost recovery from customers subject to state legislation.

FERC. In April 1996, pursuant to its authority under Sections 205 and 206 of the FPA, the FERC issued its Order No. 888. Order No. 888 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to (i) file open access transmission tariffs containing minimum terms and conditions of non-discriminatory service and (ii) take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. Additionally, Order No. 888 permits public utilities to seek recovery of legitimate, prudent and verifiable stranded costs and provides a mechanism for the recovery of such costs. Order No. 888 also provides for recovery of costs associated with former power customers and new municipally-owned entities becoming transmission-only customers as a result of providing open access transmission if the utility had a reasonable expectation of continuing to provide service to the departing customer. Order No. 888 established criteria under which stranded costs will be evaluated for contracts entered into prior to July 11, 1994, and for stranded costs resulting from the formation of any new municipal utilities. Recovery of stranded costs under contracts entered into after July 10, 1994, will be governed by the terms of those contracts.

In April 1996, the FERC also issued Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct* ("Order No. 889"). Order No. 889 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to develop and maintain an Open Access Same-Time Information System that will give existing and potential transmission users access to transmission related information on a basis consistent with that available to a utility's employees engaged in the buying and selling of power. Order No. 889 further requires public utilities to separate their transmission and generation marketing functions and communications and adopt standards of conduct ensuring that all open access transmission customers are treated in a non-discriminatory manner.

Texas. In February 1996, the Texas Commission adopted a rule governing wholesale transmission access, as required by recent Texas legislation. The Texas Commission does not have jurisdiction over the Company's wholesale transactions. However, the rule required the Company to file its FERC-approved open access transmission tariffs with the Texas Commission to certify compliance with the Texas legislation.

During 1996, pursuant to the directives of the Texas Legislature in legislation passed in 1995, the Texas Commission conducted projects to evaluate the (i) scope of competition in the electric industry in Texas and (ii) potential for stranded investment, procedures for allocating stranded costs and acceptable methods of stranded cost recovery. The Texas Commission's report consolidating the two projects was issued in January 1997. While it recommended a careful and deliberate approach to continued expansion of competition in the Texas electric market, ultimately leading to retail competition with certain safeguards, it also recommended against any legislation that would introduce broad based retail competition before 2000. The Texas Commission quantified the potential "excess of cost over market" ("ECOM") at both wholesale and retail levels under several scenarios. With respect to the Company's potential for stranded costs, the Texas Commission estimated no wholesale ECOM, and estimated retail ECOM ranging from a high of $1.3 billion to a low of $781.0 million, with an expected value of $1.1 billion, assuming full retail access in 1998. The Company cannot determine at this time the effects that would occur, including any possible effects on the Rate Stipulation, as the result of any broad based competition legislative action, if any, implemented in 1997.

New Mexico. The New Mexico Commission initiated a notice of inquiry regarding competition and the restructuring of regulation of the electric industry in 1996. The New Mexico Commission received comments from numerous parties representing various interests and conducted workshops in an attempt to arrive at a consensus with respect to the need for regulatory change, the nature of such change and the timing/transition of any changes. No consensus was reached by the participants. With respect to stranded costs, the New Mexico Commission applied the same ECOM model that was developed for Texas. The Company's New Mexico ECOM calculation ranged from a high of $248 million to a low of $173 million. The Company also provided the New Mexico Commission with its calculation of stranded costs for New Mexico pursuant to FERC Order No. 888, which equaled $364 million.

Executive Officers of the Company

Name	Age	Current Position and Business Experience
James S. Haines	50	Chief Executive Officer, President and Director since May 1996; Executive Vice President and Chief Operating Officer of Western Resources, Inc. from June 1995 to May 1996; Executive Vice President and Chief Administrative Officer of Western Resources, Inc. from April 1992 to June 1995.
Eduardo A. Rodriguez	41	Senior Vice President – Customer and Corporate Services since August 1996; Senior Vice President since January 1994; Vice President from April 1992 to January 1994; General Counsel from 1988 to August 1996; Secretary from January 1989 to January 1994.
J. Frank Bates	46	Vice President – Transmission and Distribution since August 1996; Vice President – Operations from May 1994 to August 1996; Vice President – Customer Services Texas Division from June 1989 to May 1994.
Michael L. Blough	41	Vice President – Administration since August 1996; Vice President since May 1995; Controller and Chief Accounting Officer from November 1994 to August 1996; Assistant Vice President – Financial Planning from September 1990 to November 1994.
Gary R. Hedrick	42	Vice President, Treasurer and Chief Financial Officer since August 1996; Treasurer since March 1996; Vice President – Financial Planning and Rate Administration from September 1990 to August 1996.
John C. Horne	48	Vice President – Power Generation since August 1996; Vice President – Power Supply from May 1994 to August 1996; Vice President – Transmission Systems Division from August 1989 to May 1994.
Robert C. McNiel	50	Vice President – Public Affairs and Marketing since August 1996; Vice President – New Mexico Division from December 1989 to August 1996.
Terry Bassham	36	General Counsel since August 1996; Shareholder with Clark, Thomas & Winters, P.C. from May 1993 to August 1996; Shareholder with Moreno, Fry & Bassham from February 1992 to May 1993; Shareholder with Kemp, Smith, Duncan & Hammond, P.C. for more than one year prior to February 1992.
Guillermo Silva, Jr.	43	Secretary since January 1994; Assistant Secretary from June 1989 to January 1994.

The executive officers of the Company are elected annually and serve at the discretion of the Board of Directors.

Item 2. Properties

The principal properties of the Company are described in Item 1, "Business," and such descriptions are incorporated herein by reference. Transmission lines are located either on private rights-of-way, easements or on streets or highways by public consent. See Part II, Item 8, "Financial Statements and Supplementary Data – Note H of Notes to Financial Statements" for information regarding encumbrances against the principal properties of the Company.

Item 3. Legal Proceedings

Litigation with Central and South West Corporation

In May 1993, the Company entered into the Merger Agreement, pursuant to which the Company would have been acquired by CSW. In June 1995, CSW terminated the Merger Agreement. In response, the Company filed a complaint against CSW in the 205th Judicial District Court of El Paso County, Texas, alleging, among other claims, breach of contract, breach of duty of good faith and fair dealing, breach of fiduciary duty, business disparagement, tortious interference with contract and fraud in the inducement. The Company sought an unspecified amount of damages, punitive damages, attorneys' fees and costs. In June 1995, CSW filed an adversary proceeding against the Company in the Bankruptcy Court seeking the recovery of termination fees of $25 million, approximately $3.7 million in attorneys' fees and expenses that CSW claims it advanced on behalf of the Company in certain regulatory proceedings, and $25 million for the alleged violation of the Merger Agreement's no-solicitation provisions. All of the claims by both parties were tried in the Bankruptcy Court. The trial concluded on January 30, 1997, and the matter has been taken under advisement by the presiding judge. A ruling is expected in March 1997. The Company cannot predict the outcome of this litigation. Pursuant to the terms of the Reorganization, the first $20 million in proceeds, if any, to the Company from this litigation will be distributed to the holders of preferred stock and common stock of the Predecessor Company.

Litigation with Las Cruces

Las Cruces is attempting to replace the Company as its electric service provider by acquiring, through condemnation or otherwise, the distribution assets and other facilities used to provide electric service to customers in Las Cruces. Sales to customers in Las Cruces represented approximately 7% of the Company's operating revenues in 1996. Las Cruces has two actions pending against the Company in federal district court in New Mexico, one seeking to recover franchise fees despite the expiration of the Company's Las Cruces franchise in March 1994 and one seeking a declaratory judgment that Las Cruces can proceed with a condemnation action against the Company. In addition, the New Mexico State Legislature has recently passed a bill that would allow Las Cruces to proceed with the condemnation.

In the franchise fee action, Las Cruces is seeking the reasonable value of the Company's use, occupation and rental of Las Cruces' rights-of-way or damages for trespass and an unspecified amount of punitive damages. The Company has filed an answer denying that it has any liability or continuing payment obligation to Las Cruces regarding franchise fees or use of the Las Cruces rights-of-way, and also denies that it has committed any trespass. The Company intends to vigorously defend the lawsuit. The Company has also filed a counterclaim seeking to condemn, pursuant to statutory authority, those Las Cruces rights-of-way currently used and occupied by the Company. Las Cruces has filed an answer contesting the Company's right to proceed with such a condemnation. In August 1996, the court severed the Company's counterclaim from Las Cruces' claims for all purposes, and stayed all proceedings on the Company's counterclaim until further order of the court. The trial of Las Cruces' claims is set for May 1997. The Company has reserved in its financial statements an amount equal to the franchise fees under the expired agreement.

In April 1995, Las Cruces filed a Complaint for Declaratory Judgment against the Company in the District Court for Dona Ana County, New Mexico, seeking a declaratory judgment that Las Cruces has a right of eminent domain to condemn the electric distribution system and related facilities owned and operated by the Company within and adjacent to the city limits that provide or assist in the provision of electricity within the municipal boundaries of Las Cruces. In May 1995, the Company removed the case to the United States District Court for the District of New Mexico. In October 1995, the Company's motion for summary judgment was denied and the Court ruled that although Las Cruces lacks express statutory authority to condemn the Company's assets, such express authority is required only if the proposed condemnation would materially impair, obliterate or destroy the existing use. Following a trial on the merits, the federal magistrate issued an opinion holding that Las Cruces had not met its burden of proof that its plan would not materially impair the public use of the Company's property sought to be condemned. The magistrate also granted the Company's motion to certify to the New Mexico Supreme Court the question as to whether Las Cruces possesses the authority to condemn the Company's property for use as a municipal utility when that property is already devoted to public use. In February 1997, the New Mexico Supreme Court heard oral arguments and is expected to issue its ruling in the near future.

In March 1997, the New Mexico House of Representatives and Senate passed a bill that would give Las Cruces the authority to acquire and operate the Company's distribution system within both the city limits and a territory within five miles of the municipal boundary. If the Governor signs the bill, it would become law immediately and most likely make the issues presented to the New Mexico Supreme Court moot.

Las Cruces has taken several actions to position itself to acquire portions of the Company's distribution system and certain related facilities in the event it can proceed with condemnation. See Item 1, "Business – Regulation – Federal Regulatory Matters" for discussion regarding Las Cruces' filing with the FERC for determination of stranded cost. In June 1994, the Las Cruces City Council approved a resolution selecting SPS to provide operation and maintenance services for the proposed Las Cruces electric distribution system, substations and associated transmission facilities and authorizing the staff of Las Cruces to negotiate a contract with SPS related to such services. In August 1994, SPS and Las Cruces entered into a fifteen-year contract granting SPS the right to provide all of the electric power and energy required by Las Cruces during the term of the contract. In addition, Las Cruces announced that, in October 1995, it sold approximately $73 million in revenue bonds to provide funding to finance the acquisition by condemnation or negotiated purchase of the Company's electrical distribution assets within and adjacent to the Las Cruces city limits.

The Company has filed a lawsuit in the Dona Ana County District Court and is pursuing a complaint simultaneously before the New Mexico Commission challenging the legality of the sale of the revenue bonds, and the New Mexico Commission is investigating the agreement between SPS and Las Cruces which would grant, in certain circumstances, Las Cruces an option to sell electric utility assets acquired through condemnation to SPS. In August 1996, the Dona Ana County District Court issued an opinion letter stating that Section 3-23-3 of the New Mexico Municipal Code is inapplicable to home rule municipalities and Las Cruces, therefore, was not required to acquire the New Mexico Commission's approval before issuing revenue bonds to acquire utility property. However, the Court did agree with the Company that the revenue bonds, in this case backed by utility revenues, are subject to the same requirements of other revenue bonds backed by gross receipts tax revenues. Therefore, if the Court's finding of the applicability of Las Cruces' home rule authority is overturned on appeal, the Company's position that the issuance of the bonds required prior approval could be upheld. The Court's order was signed and entered in November 1996. The Company has filed an appeal with the New Mexico Court of Appeals.

The Company continues to believe that it can provide lower cost electric service to customers in Las Cruces than can be achieved through a municipal takeover. Accordingly, the Company has stated its strong preference for a resolution of its differences with Las Cruces through negotiation rather than litigation and condemnation. The Company intends to vigorously pursue before the FERC its right to recover stranded costs from Las Cruces in the event Las Cruces succeeds in leaving the system.

If Las Cruces succeeds in its efforts to condemn the Company's distribution system, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court under New Mexico law. "Just compensation" is generally defined as the amount of money that would compensate the party whose property is condemned. In the Company's case, this amount would be the difference between the value of the Company's entire system prior to the taking, as compared to the value of the entire system after the taking. The Company is unable to predict the outcome of Las Cruces' efforts or the effects it may have on the Company's financial position, results of operations and cash flows.

Transmission Service to Mexico

In September 1996, Enron, a wholesale power marketer and one of the companies that submitted a bid to the CFE in connection with renewal of the interchange agreement for the supply of power to Ciudad Juarez, Mexico, filed a complaint against the Company with the FERC. Enron's complaint sought emergency relief and requested the FERC to direct the Company to enter into an agreement with Enron to provide Enron with firm point-to-point transmission service to the CFE under its open access transmission tariff.

In October 1996, the FERC issued an order requiring the Company to provide Enron with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction. Pursuant to an emergency application filed by Enron with the DOE, on October 30, 1996, the DOE issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties in this case. In its response to the DOE's delegation of authority, the Company has asserted that the DOE has no authority to require transmission access for delivery of power to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder in 1997, if the winning bidder is someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position that, under current law, access is not required. The FERC has docketed the Delegation and Assignment and the process is expected to continue throughout 1997.

Water Cases

San Juan River System. The Four Corners Participants are among the defendants in a suit filed by the State of New Mexico in 1975 in state district court in New Mexico against the United States of America, the City of Farmington, New Mexico, the Secretary of the Interior as Trustee for the Navajo Nation and other Indian tribes and certain other defendants (*State of New Mexico ex rel. S. E. Reynolds, New Mexico State*

Engineer v. United States of America, et al., Eleventh Judicial District Court, County of San Juan, State of New Mexico, Cause No. 75-184). The suit seeks adjudication of the water rights of the San Juan River Stream System in New Mexico, which, among other things, supplies the water used at Four Corners. The case has been inactive for many years. The Company cannot predict the outcome of this case.

Gila River System. In connection with the construction and operation of Palo Verde, APS entered into contracts with certain municipalities granting APS the right to purchase effluent for cooling purposes at Palo Verde. In 1986, a summons was served on APS that required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water in an action pending in Maricopa County Superior Court, titled *In re The General Adjudication of All Rights to Use Water in the Gila River System and Source.* Palo Verde is located within the geographic area subject to the summons and the rights of the Palo Verde Participants to the use of groundwater and effluent at Palo Verde is potentially at issue in the action. APS, as operating agent, filed claims that dispute the court's jurisdiction over the Palo Verde Participants' groundwater rights and their contractual rights to effluent relating to Palo Verde and, alternatively, seek confirmation of such rights. In December 1992, the Arizona Supreme Court heard oral argument on certain issues in this matter that are pending on interlocutory appeal. Issues important to Palo Verde Participants' claims were remanded to the trial court for further action and the trial court certified its decision for interlocutory appeal to the Arizona Supreme Court. In September 1994, the Arizona Supreme Court granted review of the June 1994 trial court decision. No trial date has been set in the matter. The Company cannot predict the outcome of this case.

Four Corners

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the "Acts"). In October 1995, the Four Corners Participants requested that the United States Secretary of the Interior resolve their dispute with the Navajo Nation regarding whether the Acts apply to operation of Four Corners. The Four Corners Participants subsequently filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that (i) the Four Corners leases and federal easements preclude the application of the Acts to the operation of Four Corners; and (ii) the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners. On October 18, 1995, the Navajo Nation and the Four Corners Participants agreed to indefinitely stay the proceedings referenced above so that the parties may attempt to resolve the dispute without litigation. The Company is unable to predict the outcome of this matter.

Other Legal Proceedings

The Company is a party to various other claims, legal actions and complaints. In many of these matters, the Company has excess casualty liability insurance which is applicable. Based upon a review of these claims and applicable insurance coverage, management is of the opinion that none of these claims will have a material adverse effect on the operations or financial position of the Company.

Item 4. Submission of Matters to a Vote of Security Holders

On November 14, 1996, the Company held a Special Shareholders Meeting to approve the Company's 1996 Long-Term Incentive Plan, which authorized the issuance of up to 3,500,000 shares of common stock for the benefit of officers, key employees and non-employee directors through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock and performance stock. The total number of common shares outstanding at this Special Meeting was 59,999,981, of which 46,078,152 were represented in person or by proxy. Shares voted in favor of approving the plan were 38,325,050, and shares voted against were 7,308,727. There were 444,375 abstentions. Broker non-votes were not included in the determination of the number of shares represented at the meeting for purposes of determining whether a quorum was present and were not counted for purposes of determining whether the proposal had been approved. See Part II, Item 8, "Financial Statements and Supplementary Data – Note F of Notes to Financial Statements."

PART II

Item 5. Market for Registrant's Common Equity and Related Stockholder Matters

The Company's Common Stock began trading on the American Stock Exchange on February 16, 1996 under the symbol "EE:" The high and low sales prices for the Company's Common Stock, as reported in the consolidated reporting system of the American Stock Exchange, for the periods indicated below, were as follows:

	Sales Price	
	High	Low
1996		
February 16 - March 31	$ 6 1/4	$ 4 3/4
Second Quarter	6 1/8	5
Third Quarter	6 1/8	5 1/4
Fourth Quarter	6 5/8	4 15/16

At March 20, 1997, there were 11,847 record holders of the Company's Common Stock.

The Company's ability to pay dividends on the Common Stock for the next several years will be limited by applicable law and, as explained below, by the financing arrangements entered into pursuant to the Reorganization. All distributions with respect to the Common Stock, including the declaration or payment of dividends, are subject to the provisions of the Texas Business Corporation Act, including provisions that prohibit any distribution that exceeds the surplus of the Company. In addition, under Section 305 of the FPA, it is unlawful for a director or officer of the Company to participate in the making or payment of dividends from "any funds properly included in capital account." As a result of Reorganization, the Company's first priority at this time is debt retirement and deleveraging as opposed to paying dividends.

Pursuant to the resolutions creating the Company's Series A Preferred Stock, no dividends can be paid on the Common Stock if there are dividends in arrears on the Series A Preferred Stock. So long as the Company's First Mortgage Bonds, Series A through H, are outstanding and the series with the longest maturity is not rated "investment grade" by either Standard & Poor's Rating Service or Moody's Investors Service, Inc., the Company may not declare any dividend on the Common Stock, other than in additional shares of Common Stock, or make any other distribution on, or acquire for value any shares of Common Stock (with certain limited exceptions) unless, after giving effect thereto, the aggregate of all such dividends, distributions and certain other payments made by the Company since February 12, 1996 would be less than the sum of (i) 50% of the consolidated net income (as defined in the mortgage indenture) of the Company minus dividends paid in respect of the Series A Preferred Stock for the period from February 13, 1996 to the most recently ended fiscal quarter for which quarterly financial statements are available (or, if such consolidated net income is a deficit, less 100% of such deficit), plus (ii) 100% of the aggregate net proceeds received by the Company from the issuance or sale since February 12, 1996 of equity securities or debt securities that have been converted into equity securities, plus (iii) $10.0 million. Currently, the Company's First Mortgage Bonds are not rated investment grade.

Pursuant to the terms of the reimbursement agreements related to four letters of credit issued in respect to the four series of pollution control revenue bonds, so long as a drawing is available under any of the letters of credit, the same limitation on the declaration of dividends would apply to the Company. In addition to the restriction contained in the mortgage indenture, the reimbursement agreements limit to $15.0 million the aggregate amount of dividends that can be paid on the Common Stock during the three years after its initial issuance on February 12, 1996. The credit agreement for the working capital and fuel financing facility contains the same limitations on the payment of Common Stock dividends as the reimbursement agreements related to the letters of credit on the pollution control revenue bonds.

Item 6. Selected Financial Data

As of and for the following periods:

	Reorganized Company	Predecessor Company					
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994	1993	1992
			(In thousands except for share data)			
Operating revenues	$ 523,974	$ 54,949	$ 504,617	$ 536,760	$ 543,594	$ 524,760
Operating income	120,787	5,089	66,146	73,011	64,971	67,036
Income (loss) before extraordinary gain on discharge of debt and cumulative effect of a change in accounting principle	41,919	118,198	(33,319)	(28,153)	(41,855)	(28,180)
Extraordinary gain on discharge of debt	–	264,273	–	–	–	–
Cumulative effect of a change in accounting principle	–	–	–	–	(96,044)(1)	–
Net income (loss) applicable to common stock	31,431	382,471	(33,319)	(28,153)	(137,899)	(28,180)
Net income (loss) per common share:						
Income (loss) before extraordinary gain on discharge of debt and cumulative effect of a change in accounting principle	0.52	3.33	(0.94)	(0.79)	(1.18)	(0.79)
Extraordinary gain on discharge of debt	–	7.43	–	–	–	–
Cumulative effect of a change in accounting principle	–	–	–	–	(2.70)(1)	–
Net income (loss) per common share	0.52	10.76	(0.94)	(0.79)	(3.88)	(0.79)
Weighted average number of common shares and common share equivalents outstanding	60,181,494	35,544,330	35,544,330	35,544,330	35,539,480	35,530,264
Total assets	1,846,190	1,910,354	1,809,891	1,730,851	1,715,406	1,702,778
Additions to utility plant	53,018	8,231	88,267	60,113	58,215	60,570
Long-term debt, financing and capital lease obligations	1,046,173	1,164,328	–	–	–	–
Debt and obligations subject to compromise	–	–	1,608,091	1,537,303	1,495,315	1,440,968
Preferred stock	108,426	100,000	81,464	81,464	81,464	81,464
Common stock equity (deficit)	331,257	300,000	(418,763)	(385,966)	(357,463)	(220,508)

(1) Reflects the change in accounting for income taxes due to the implementation of SFAS No. 109, "Accounting for Income Taxes" ("SFAS No. 109").

The selected financial data should be read in conjunction with Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," and Item 8, "Financial Statements and Supplementary Data," below.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Statements in this document, other than statements of historical information, are forward-looking statements that are made pursuant to the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 (the "1995 Act"). Such forward-looking statements, as well as other oral and written forward-looking statements made by or on behalf of the Company from time to time, including statements contained in the Company's filings with the Securities and Exchange Commission and its reports to stockholders, involve known and unknown risks and other factors which may cause the Company's actual results in future periods to differ materially from those expressed in any forward-looking statements. Any such statement is qualified by reference to the risks and factors discussed below under the headings "Operational Prospects and Challenges" and "Liquidity and Capital Resources" and in the Company's filings with the Securities and Exchange Commission, which are available from the Securities and Exchange Commission or which may be obtained upon request from the Company. The Company cautions that the foregoing list of important factors is not exclusive. The Company does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of the Company.

Operational Prospects and Challenges

While the Company prepares for a new era of deregulation and competition in the electric utility industry, the Rate Stipulation provides a certain level of stability in the rates that the Company currently charges the majority of its customers. The Company intends to enhance its position during the Freeze Period by (i) serving the growing need for electricity within its retail service territory; (ii) continuing to focus on its strategic location on the border with Mexico; (iii) executing long-term contracts to provide electricity to its largest retail customers; and (iv) implementing operating cost reduction programs.

The Company faces a number of challenges which could negatively impact its operations during the Freeze Period. The primary challenge is the risk of increased costs, including the risk of additional or unanticipated costs, at Palo Verde resulting from (i) increases in operation and maintenance expenses; (ii) the potential replacement of steam generators; (iii) an extended outage of any of the Palo Verde units; (iv) increases in estimates of decommissioning costs; (v) the storage of radioactive materials; and (vi) compliance with the various requirements and regulations governing commercial nuclear generating stations. There can be no assurance that the Company's revenues will be sufficient to recover any increased costs incurred during the Freeze Period, including any such increased costs in connection with Palo Verde or increases in other costs of operation, whether as a result of higher than anticipated levels of inflation, changes in tax laws or regulatory requirements, or other causes.

In recent months, rapid escalation in fuel prices have increased concern over price levels for energy, including electricity. The Company's recovery of fuel expense is subject to challenges regarding reasonableness and prudence through periodic fuel reconciliation proceedings. See Part I, Item 1, "Business – Regulation – Texas Rate Matters – Fuel" and "– Regulation – New Mexico Rate Matters – Fuel."

Another risk to the Company's operations is the potential loss of customers. The Company's wholesale and large retail customers currently have, in varying degrees, and, in the future may have, additional alternate sources of economical power, including co-generation of electric power. If the Company loses a significant portion of its retail customer base or wholesale sales, the Company may not be able to replace such revenues through either the addition of new customers or an increase in rates to remaining customers. Las Cruces has begun litigation and the New Mexico State Legislature has passed legislation which, if signed by the Governor, would give Las Cruces the legal authority to condemn the Company's distribution system and related assets located within its city limits. If Las Cruces succeeds in its efforts, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court. See Item 8, "Financial Statements and Supplementary Data – Note K of Notes to Financial Statements." Further, there are state and federal legislative initiatives related to deregulation which could affect Company operations.

In recent years, the United States has closed a large number of military bases and there can be no assurance that Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") or the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss") will not be closed in the future or that the Company will not lose all or some of its military base sales. The Company's sales to the military bases represented approximately $20.0 million or 3% of operating revenues for the year ended December 31, 1996. The Company signed a new contract with Ft. Bliss in August 1996, which provides that Ft. Bliss will take service from the Company through 1999, with the right thereafter to continue service on a year to year basis for two years. The Company has a contract for service to Holloman for a ten-year term beginning in December 1995. In August 1996, the Army advised the Company that White Sands would continue to purchase retail electric service from the Company pursuant to the retail service contract which was set to expire on December 31, 1993, but which had previously been unilaterally extended by the Army for an indefinite period, until written termination of such contract by the Army not less than one year in advance of the termination date.

The Company does not currently have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation. Pursuant to an order from the New Mexico Commission, the Company filed rate data with the Commission on March 3, 1997. Although the Company's filing demonstrates a revenue deficiency of approximately $8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Finally, the electric utility industry in general is facing significant challenges and increased competition as a result of changes in federal provisions relating to third-party transmission services and independent power production, as well as potential changes in state regulatory provisions relating to wholesale and retail service. Both the Texas and New Mexico Commissions are conducting proceedings related to industry restructuring and stranded cost recovery. See Part I, Item 1, "Business – Regulation – Recent Changes in Utility Regulation." The Company cannot predict the outcome of these proceedings. The potential effects of deregulation are particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flow and financial condition of the Company.

Liquidity and Capital Resources

The Company's principal liquidity requirements through the end of the decade are expected to consist of the payment of interest on the Company's indebtedness and capital expenditures related to the Company's generating facilities and transmission and distribution systems. The Company expects that cash flows from operations will be sufficient for such purposes.

Long-term capital requirements of the Company will consist primarily of maintenance and construction of electric utility plant, payment of interest on and retirement of debt and payment of dividends on and redemption of preferred stock. The Company has no current plans to construct any new generating capacity through at least 2004. Utility construction expenditures will consist primarily of expanding and updating the transmission and distribution systems and the cost of betterments and improvements to Palo Verde and other generating facilities.

The Company anticipates that internally generated funds will be sufficient to meet its construction requirements, provide for the retirement of debt at maturity and enable the Company to meet other contingencies that may exist, such as compliance with environmental regulation, pending litigation and any claims for indemnification. At December 31, 1996, the Company had approximately $68.8 million in cash and cash equivalents, out of which approximately $9.1 million of reorganization expenses are expected to be paid upon receipt of the Bankruptcy Court's final order for allowable professional fees related to the Company's bankruptcy proceedings. The Company also has a $100 million revolving credit facility, which provides up to $60 million for nuclear fuel purchases and up to $50 million (depending on the amount of borrowings outstanding for nuclear fuel purchases) for working capital needs. At December 31, 1996, approximately $46.6 million had been drawn for nuclear fuel purchases. No amounts have been drawn on this facility for working capital needs.

The Company has substantial leverage and significant debt service obligations and, primarily due to the Rate Stipulation, does not expect to be able to raise its base rates in order to recover any future increases in non-fuel costs or to replace any lost revenues. As of December 31, 1996, the Company had total long-term indebtedness, including the long-term portion of financing and capital lease obligations, of approximately $1,046 million and redeemable preferred stock of $108 million. Long-term indebtedness as a percentage of total capitalization totaled approximately 70%.

From June 1996 through March 20, 1997, the Company repurchased approximately $168 million of its first mortgage bonds, which repurchases, net of related issuance cost, did not result in a material net gain or loss. From time to time, based on prevailing market conditions, the Company intends to continue to use a portion of its available cash flow to reduce fixed obligations by making open market purchases of first mortgage bonds.

The degree to which the Company is leveraged could have important consequences on the Company's liquidity, including (i) the Company's ability to obtain additional financing for working capital, capital expenditures, acquisitions, general corporate purposes or other purposes could be limited in the future; (ii) a substantial portion of the Company's cash flow from operations will be dedicated to the payment of principal and interest on its indebtedness, thereby reducing the funds available to the Company for other purposes; and (iii) the Company's substantial leverage may place the Company at a competitive disadvantage, hinder its ability to adjust rapidly to changing market conditions and make it more vulnerable in the event of a downturn in general economic conditions or its business. As a result, any significant reduction in revenues and/or significant increase in costs or expenditures could adversely affect the Company's liquidity.

Historical Results of Operations

General

The Company derives revenue principally from the sale of power to retail and wholesale customers, which accounted for 80.8% and 18.5%, respectively, of the Reorganized and Predecessor Companies' combined revenues for the year ended December 31, 1996, and 79.6% and 19.7%, respectively, of the Predecessor Company's revenues for the year ended December 31, 1995. Revenues from the sale of electricity include fuel revenues based upon fuel costs, which are generally passed through directly to customers, and base revenues. Base revenues refers to the Company's revenues from the sale of electricity excluding such fuel revenues.

The Company's retail customers consist of residential customers, small commercial and industrial customers, large commercial and industrial customers and public authorities, which accounted for 36%, 36%, 11% and 17%, respectively, of the Company's retail base revenues for the year ended December 31, 1996 and 36%, 36%, 11% and 17%, respectively, of the Company's retail base revenues for the year ended December 31, 1995. Wholesale revenues consist of sales pursuant to long-term power contracts, sales to CFE, and spot market sales, which accounted for 51%, 36% and 13%, respectively, of the Company's wholesale base revenues for the year ended December 31, 1996 and 56%, 36% and 8%, respectively, of the Company's wholesale base revenues for the year ended December 31, 1995. Sales to the Company's largest wholesale customer, IID, accounted for 7.5% and 8.8% of the Company's base revenues for the years ended December 31, 1996 and 1995, respectively. No retail customer accounted for more than 3% of the Company's base revenues during such periods.

The Company's business is seasonal, with higher revenues generated during the summer season. The following table sets forth the percentage of the Company's revenues derived during each quarter of the periods presented.

	Years Ended December 31,		
	1996	1995	1994
First Quarter	21%	22%	23%
Second Quarter	25	25	26
Third Quarter	29	29	29
Fourth Quarter	25	24	22
Total	100%	100%	100%

Palo Verde, which provides approximately 40% of the Company's available net generating capacity and provided approximately 53% of the Company's available energy for the year ended December 31, 1996, is subject to performance standards in New Mexico and Texas. If such performance standards are not met, the Company is subject to a penalty. If standards are exceeded, the Company is entitled to a reward. See Part I, Item 1, "Business – Regulation – New Mexico Rate Matters – Palo Verde Performance Standards" and "– Regulation – Texas Rate Matters – Palo Verde Performance Standards."

Year Ended December 31, 1996 Compared to Year Ended December 31, 1995

Operating Revenues

Combined operating revenues for the Reorganized Company and Predecessor Company increased 14.7% to $578.9 million in 1996 compared to $504.6 million in 1995 primarily due to (i) increased base revenues and (ii) increased fuel revenues. The Company achieved record total system peak demand of 1,387 MW in 1996, representing a 0.9% increase over 1995's record peak of 1,374 MW.

Base Revenues. Combined base revenues increased 6.7% to $460.9 million in 1996 compared to $432.0 million in 1995, primarily due to an increase in Texas base rates associated with the implementation of the Rate Stipulation and an increase in KWH sales.

KWH sales increased 4.9% in 1996 compared to 1995 primarily due to (i) warm weather and (ii) a 1.9% increase in the average number of customers served.

	KWH Sales		Increase
	1996	1995	(Decrease)
	(In thousands)		
Retail	5,652,907	5,416,902	4.4%
Wholesale	1,753,553	1,646,357	6.5%
Total	7,406,460	7,063,259	4.9%

Fuel Revenues and Economy Sales. Regulations of the Texas and New Mexico Commissions allow substantially all fuel and purchased and interchanged power costs to be passed through directly to customers. These costs are reflected in the Company's fuel revenues. Combined fuel revenues and economy sales increased 65.7% to $114.0 million in 1996 compared to $68.8 million in 1995 primarily due to (i) increased fuel and purchased and interchanged power costs; (ii) increased economy energy sales; and (iii) changes in the Texas fuel revenue calculation associated with the implementation of the Rate Stipulation.

Fuel and Purchased and Interchanged Power Expense

Combined fuel and purchased and interchanged power expense (substantially all of which is expected to be recovered by the Company in fuel revenues as described above) increased 33.0% to $123.1 million in 1996 compared to $92.6 million in 1995. Such increase was primarily due to increased cost of natural gas and volume of fuel used in Company-owned generation and to increased volume of higher cost purchased power resulting from (i) increased KWH sales in 1996 and (ii) the timing and duration of maintenance outages at Company-owned plants, and refueling outages at Palo Verde in 1996 compared to 1995.

Other Operation and Maintenance Expense

Combined other operation and maintenance expense decreased 29.0% to $178.7 million in 1996 compared to $251.9 million in 1995 due to decreased Palo Verde costs of approximately $72.0 million. The reduction in Palo Verde costs consisted of approximately $67.3 million associated with lease accruals recorded in 1995, with no corresponding accrual in 1996 by the Reorganized Company as a result of the reacquisition of the leased portion of Palo Verde in the Reorganization, and approximately $4.7 million primarily from the timing and duration of unit refuelings during the periods.

Depreciation and Amortization Expense

Combined depreciation expense increased $29.6 million to $86.3 million in 1996 compared to $56.8 million in 1995. The effect of an increase in depreciable plant following the reacquisition in the Reorganization of a portion of Palo Verde was partially offset by the decrease in the book value of depreciable plant from fresh-start adjustments. The effect of the implementation of fresh-start reporting and the accelerated depreciation of a portion of such amounts over the period of the Rate Stipulation resulted in increased depreciation expense of $37.2 million for the period February 12, 1996 to December 31, 1996 partially offset by decreased nuclear decommissioning amortization. As part of the adoption of fresh-start reporting, the Company recognized the net present value of estimated future expenditures for nuclear decommissioning of approximately $84.9 million.

Federal Income Taxes

Combined federal income tax expense, excluding the deferred income tax effects of fresh-start reporting, reorganization items and income taxes on interest income during bankruptcy, increased $29.8 million to $19.0 million in 1996 compared to a tax benefit of $10.8 million in 1995 primarily due to changes in pretax income and certain differences in book and taxable income.

State Income Taxes

Combined state income tax expense, excluding deferred income taxes recognized in reorganization items, increased $9.3 million to $4.3 million in 1996 compared to a state tax benefit of $5.0 million in 1995 primarily due to changes in pretax income and certain differences in book and taxable income.

Other Taxes

Combined taxes other than income taxes decreased $9.0 million to $44.6 million in 1996 compared to $53.6 million in 1995 primarily due to (i) a decrease in Arizona property tax resulting from a new state property tax law which reduced the property taxes for 1996; (ii) a decrease in taxable property base resulting from depreciation; and (iii) the elimination of Arizona sales tax on lease payments due to reacquisition of leased property in February 1996. The decrease was partially offset by an increase in revenue related tax. Under the recently enacted law in Arizona, the Company's property taxes were approximately $17.1 million for 1996, a reduction of approximately $8.8 million from 1995.

Gain on Sale of Investment

In August 1996, the Company's warrant to buy up to 49.75% of the equity interest in CAI Corporation was sold for $20.2 million. The sale resulted in a pretax gain of $3.8 million based on a book value of $16.4 million.

Investment Income

Combined investment income on cash for the Reorganized Company is classified as Other Income, whereas investment income on cash for the Predecessor Company is included in Reorganization Items (Expense). Combined investment income decreased 52.7% to $6.3 million in 1996 compared to $13.2 million in 1995 due to reduced levels of cash resulting from repurchases of debt and the payment of bankruptcy related claims pursuant to the Plan.

Settlement of Bankruptcy Professional Fees

The Company recorded a change in estimate of approximately $2.3 million related to accrued professional fees as a result of Bankruptcy Court proceedings.

Interest Charges

Combined interest charges increased 8.1% to $95.3 million in 1996 compared to $88.1 million in 1995 primarily due to (i) increased interest on mortgage bonds due to a greater amount of bonds being outstanding subsequent to the Reorganization, and (ii) accretion of the nuclear decommissioning liability as a result of implementing fresh-start reporting. This increase was partially offset by decreased interest charges due to the extinguishment of certain debt in conjunction with the Reorganization.

Reorganization Items

Reorganization items for the Predecessor Company for the period January 1, 1996 to February 11, 1996 was a benefit of $122.2 million compared to an expense of $10.0 million for the twelve months ended December 31, 1995. The benefits recorded by the Predecessor Company upon the emergence from bankruptcy consisted of deferred income tax benefits related to the Reorganization and the effects of the Rate Stipulation. These benefits were offset by (i) the adjustments of assets and liabilities to their fair market values; (ii) provisions for settlement of claims; and (iii) professional fees and other expenses. The reorganization expense recorded in 1995 consisted of professional fees partially offset by interest earned on accumulated cash resulting from the Bankruptcy Case. See Note B of Notes to Financial Statements.

Extraordinary Gain on Discharge of Debt

Extraordinary gain on discharge of debt for the Predecessor Company for the period January 1, 1996 to February 11, 1996 consisted of forgiveness of indebtedness primarily related to the extinguishment of Palo Verde lease obligations.

Net Income

The combined change in 1996 net income was primarily due to the extraordinary gain on discharge of debt and reorganization items related to the Company's emergence from bankruptcy, with no comparable activity in 1995.

Year Ended December 31, 1995 Compared to Year Ended December 31, 1994

Operating Revenues

Operating revenues decreased 6.0% to $504.6 million in 1995 compared to $536.8 million in 1994 primarily due to a decrease in fuel revenues. Nonetheless, the Company achieved a then record total system peak demand of 1,374 MW in 1995, representing a 0.7% increase over 1994's record peak of 1,365 MW.

Base Revenues. Base revenues remained relatively unchanged at $432.0 million in 1995 compared to $431.6 million in 1994.

Total system firm energy sales decreased to 7,063,259 MWH in 1995 from 7,321,711 in 1994. Retail firm energy sales increased 20,862 MWH over the same time period.

In July 1994, the Company implemented an increase in base rates for Texas retail customers subject to refund and bond. Accordingly, the Company deferred recognition of those revenues, which are not included in either 1995 or 1994 results. Revenues deferred for 1995 and 1994 were $24.1 million and $11.5 million, respectively, and total revenues subject to refund aggregated $35.6 million at December 31, 1995.

Fuel Revenues. Regulations of the Texas and New Mexico Commissions allow substantially all changes in fuel and purchased and interchanged power costs to be passed through directly to customers. These costs are reflected in the Company's revenues. Fuel revenues decreased 31.9% to $68.8 million in 1995 compared to $101.1 million in 1994 primarily due to reduced cost of fuel for Company-owned generation and changes in generation supply from higher cost purchased power to Company-owned generation. During the fourth quarter of 1995, the Company reserved $2.3 million against fuel revenues to reflect additional fuel and purchased and interchanged power costs incurred related to operating conditions during the initial remediation following the system outages.

If the provisions of the Rate Stipulation concerning fuel issues had been implemented for 1995, fuel revenues would have been $16.3 million greater. Under the Agreed Order, the Company retained fuel revenues in the amount of $46.1 million that had been accrued as a provision for refund in the financial statements.

Fuel and Purchased and Interchanged Power Expense

Fuel and purchased and interchanged power expense decreased 22.7% to $92.6 million in 1995 compared to $119.8 million in 1994. Such decrease was primarily attributable to the reduced cost of fuel for Company-owned generation and changes in the fuel mix from higher cost purchased power to nuclear fuel.

Other Operation and Maintenance Expense

Other operation and maintenance expense decreased 0.8% to $251.9 million in 1995 compared to $253.8 million in 1994 as a result of (i) decreased Palo Verde costs of $3.7 million; (ii) decreased rents of $1.2 million primarily related to lease expenses for the Company's computer system; (iii) decreased general maintenance costs at a Company-operated generation plant of $1.0 million; (iv) decreased pension and benefit costs of $0.9 million primarily due to a change in actuarial assumptions; and (v) decreased transmission costs of $0.8 million primarily related to the installation of transmission equipment which eliminated fees for transmission services. Such decreases were partially offset by (i) increased outside service costs of $3.3 million primarily related to condemnation and franchise issues for Las Cruces; and (ii) increased maintenance costs of $2.2 million at a Company-operated generating plant.

Depreciation and Amortization Expense

Depreciation and amortization expense increased $2.9 million to $56.8 million in 1995 compared to $53.8 million in 1994 primarily due to increases in depreciable plant balances and a $0.6 million inflation adjustment to the DOE's assessment on Palo Verde related to a Decontamination and Decommissioning Fund established by the Energy Policy Act.

Federal Income Taxes

Federal income tax benefits decreased $9.5 million to $7.3 million in 1995 compared to $16.8 million in 1994 primarily due to changes in pretax income and differences in book and taxable income.

State Income Tax

State income tax expense decreased $5.2 million to a tax benefit of $5.0 million in 1995 compared to $0.2 million expense in 1994 primarily due to a decrease in pretax income and certain differences in book and taxable income.

Other Taxes

Taxes other than income taxes decreased $0.7 million to $53.6 million in 1995 compared to $54.3 million in 1994 due to a decrease in property taxes resulting from a decrease in taxable base and a decrease in Arizona sales tax resulting from an accrual in 1994 for prior years' taxes with no corresponding accrual in 1995.

Other Income, Net

Other income, net decreased $4.3 million to a net deduction of $0.9 million in 1995 compared to other income, net of $3.4 million in 1994 primarily due to (i) a gain of $2.4 million on the sale of the Company's interest in Triangle Electric Supply Company in 1994 with no comparable gain in 1995; and (ii) the recording of $0.9 million of expense in 1995 compared to $0.5 million of income in 1994 related to Company-owned life insurance policies.

Interest Charges

Interest charges decreased $6.9 million to $88.1 million in 1995 compared to $95.0 million in 1994 primarily due to the Company's discontinuance of interest accruals on unsecured debt pursuant to Bankruptcy Court order which was offset partially by increased interest rates on interim payments to certain secured and unsecured creditors.

Reorganization Items

Reorganization items expense increased 11.0% to $10.0 million in 1995 compared to $9.0 million in 1994. Such increase of reorganization items expense was due to increased professional fees and other costs in 1995 partially offset by increased interest earned on accumulated cash in 1995 due to higher cash balances and investment interest rates.

Net Loss

Net loss increased $5.2 million to $33.3 million in 1995 compared to $28.2 million in 1994. The principal factors giving rise to the loss in 1995 were (i) that revenues were not sufficient to recover fully the Company's costs of service and debt service; and (ii) reorganization expenses.

Effects of Inflation

Over the recent past, inflation has been relatively low. As such, its impact to the Company's results of operations and financial condition has not been significant.

Effect of Recently Issued Accounting Standards

SFAS No. 128, "Earnings per Share" ("SFAS No. 128"), establishes standards for computing and presenting earnings per share and applies to entities with publicly held common stock. The effective date of SFAS No. 128 is for financial statements issued for periods ending after December 15, 1997, including interim periods; earlier application is not permitted. The Company has not performed an analysis to determine what effect, if any, SFAS No. 128 will have on its financial statements.

Item 8. Financial Statements and Supplementary Data

INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

The Shareholders and Board of Directors
El Paso Electric Company

We have audited the accompanying balance sheets of El Paso Electric Company (the "Company") as of December 31, 1996 and 1995 and the related statements of operations, accumulated earnings (deficit), and cash flows for the period February 12, 1996 to December 31, 1996, the period January 1, 1996 to February 11, 1996 and for each of the years in the two-year period ended December 31, 1995. 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 generally accepted auditing standards. 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 El Paso Electric Company as of December 31, 1996 and 1995, and the results of its operations and its cash flows for the period February 12, 1996 to December 31, 1996, the period January 1, 1996 to February 11, 1996 and for each of the years in the two-year period ended December 31, 1995 in conformity with generally accepted accounting principles.

As discussed in Notes A and B of Notes to Financial Statements, on February 12, 1996, the Company emerged from bankruptcy. The financial statements of the reorganized Company reflect assets at reorganization value and liabilities at fair value under fresh-start reporting. As a result, the financial statements of the reorganized Company are presented on a different basis than those prior to the reorganization and, therefore, are not comparable in all respects.

KPMG Peat Marwick LLP

El Paso, Texas
March 27, 1997

EL PASO ELECTRIC COMPANY
BALANCE SHEETS

ASSETS (In thousands)	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Utility plant (Notes A, C, D, E and H):		
Electric plant in service	$ 1,492,737	$ 1,744,468
Less accumulated depreciation and amortization	77,976	465,311
Net plant in service	1,414,761	1,279,157
Construction work in progress	44,432	61,274
Nuclear fuel; includes fuel in process of $5,084 and $6,071, respectively	60,014	82,904
Less accumulated amortization	18,651	43,599
Net nuclear fuel	41,363	39,305
Net utility plant	1,500,556	1,379,736
Current assets:		
Cash and temporary investments	68,767	262,507
Accounts receivable, principally trade, net of allowance for doubtful accounts of $6,161 and $6,031, respectively	57,587	59,233
Federal income tax receivable	20,713	–
Inventories, at cost	28,322	32,737
Prepayments and other	10,652	8,877
Total current assets	186,041	363,354
Long-term contract receivable (Note C)	31,057	33,683
Deferred charges and other assets:		
Accumulated deferred income taxes, net (Note I)	73,884	–
Decommissioning trust fund (Note E)	33,054	26,183
Other	21,598	6,935
Total deferred charges and other assets	128,536	33,118
Total assets	$ 1,846,190	$ 1,809,891

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
BALANCE SHEETS (Continued)

CAPITALIZATION AND LIABILITIES (In thousands except for share data)	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Capitalization (Notes A, F and G):		
Common stock, stated value $1 per share, 100,000,000 shares authorized, 59,999,981 shares issued and outstanding; and 180,000 restricted shares as of December 31, 1996	$ 60,180	$ –
Capital in excess of stated value	240,768	–
Unearned compensation – restricted stock awards	(758)	–
Predecessor common stock, no par value, 100,000,000 shares authorized, 35,544,330 shares issued and outstanding as of December 31, 1995	–	339,097
Accumulated earnings (deficit)	30,835	(758,032)
Net unrealized gain on marketable securities, less applicable income tax expense of $125 and $93, respectively	232	172
Common stock equity (deficit)	331,257	(418,763)
Preferred stock, cumulative, no par value, 2,000,000 shares authorized, Redemption required – 1,084,264 shares issued and outstanding; at liquidation preference	108,426	–
Long-term debt (Note H)	1,021,749	–
Financing and capital lease obligations (Note H)	24,424	–
Predecessor preferred stock, cumulative, no par value, 2,000,000 shares authorized:		
Redemption required	–	67,266
Redemption not required	–	14,198
Obligations subject to compromise	–	1,608,091
Total capitalization	1,485,856	1,270,792
Current liabilities:		
Current maturities of financing and capital lease obligations (Note H)	28,333	–
Accounts payable, principally trade	37,215	34,900
Taxes accrued other than federal income taxes	21,296	24,629
Interest accrued	23,150	–
Net overcollection of fuel revenues (Note C)	–	53,788
Revenues subject to refund (Note C)	–	35,582
Other	15,000	14,266
Total current liabilities	124,994	163,165
Deferred credits and other liabilities:		
Decommissioning (Note E)	89,544	47,245
Accrued postretirement benefit liability (Note L)	71,313	20,298
Accrued pension liability (Note L)	34,550	14,163
Other	39,933	17,465
Accumulated deferred income taxes (Note I)	–	70,010
Accumulated deferred investment tax credits (Note I)	–	78,275
Deferred gain on sales and leasebacks	–	128,478
Total deferred credits and other liabilities	235,340	375,934
Commitments and contingencies (Notes A, B, C, E, J, K and L)		
Total capitalization and liabilities	$ 1,846,190	$ 1,809,891

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF OPERATIONS
(In thousands except for share data)

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Operating revenues:				
Base revenues	$ 416,221	$ 44,679	$ 432,050	$ 431,634
Fuel revenues and economy sales	104,193	9,849	68,823	101,076
Other	3,560	421	3,744	4,050
	523,974	54,949	504,617	536,760
Operating expenses:				
Operation:				
Fuel	92,899	10,125	76,005	89,893
Purchased and interchanged power	17,821	2,282	16,568	29,929
	110,720	12,407	92,573	119,822
Other	115,742	23,559	208,445	209,814
Maintenance	34,702	4,743	43,412	44,022
Depreciation and amortization	79,772	6,577	56,762	53,841
Taxes:				
Federal income tax expense (benefit) (Note I)	18,659	(2,700)	(11,248)	(18,234)
State income tax expense (benefit) (Note I)	5,045	(750)	(5,024)	220
Other	38,547	6,024	53,551	54,264
	403,187	49,860	438,471	463,749
Operating income	120,787	5,089	66,146	73,011
Other income (deductions):				
Investment income	4,796	–	–	–
Gain on sale of investment	3,844	–	–	–
Settlement of bankruptcy professional fees	2,305	–	–	–
Other, net	(681)	50	(910)	3,378
Federal income tax expense applicable to other income (Note I)	(2,966)	(35)	(474)	(516)
	7,298	15	(1,384)	2,862
Income before interest charges	128,085	5,104	64,762	75,873
Interest charges (credits):				
Interest on long-term debt	85,633	–	–	–
Other interest	5,722	–	–	–
Interest during reorganization	–	9,569	91,923	97,616
Interest capitalized and deferred	(5,189)	(412)	(3,820)	(2,581)
	86,166	9,157	88,103	95,035
Income (loss) before reorganization items (expense) and extraordinary gain on discharge of debt	41,919	(4,053)	(23,341)	(19,162)
Reorganization items (expense), net of income tax benefit (expense) (Note B)	–	122,251	(9,978)	(8,991)
Income (loss) before extraordinary gain on discharge of debt	41,919	118,198	(33,319)	(28,153)
Extraordinary gain on discharge of debt (Note B)	–	264,273	–	–
Net income (loss)	41,919	382,471	(33,319)	(28,153)
Preferred stock dividend requirements	10,488	–	–	–
Net income (loss) applicable to common stock	$ 31,431	$ 382,471	$ (33,319)	$ (28,153)
Net income (loss) per common share (Note D):				
Income (loss) before extraordinary gain on discharge of debt	$ 0.52	$ 3.33	$ (0.94)	$ (0.79)
Extraordinary gain on discharge of debt	–	7.43	–	–
Net income (loss)	$ 0.52	$ 10.76	$ (0.94)	$ (0.79)

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF ACCUMULATED EARNINGS (DEFICIT)
(In thousands except for share data)

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Accumulated earnings (deficit) at beginning of period	$ –	$ (758,032)	$ (724,713)	$ (696,560)
Add:				
Net income (loss)	41,919	382,471	(33,319)	(28,153)
Elimination of predecessor equity accounts (Note A)	–	375,561	–	–
	41,919	758,032	(33,319)	(28,153)
Deduct:				
Cumulative preferred stock dividend requirement	10,488	–	–	–
Capital stock expense	596	–	–	–
	11,084	–	–	–
Accumulated earnings (deficit) at end of period	$ 30,835	$ –	$ (758,032)	$ (724,713)
Weighted average number of common shares and common share equivalents outstanding	60,181,494	35,544,330	35,544,330	35,544,330

See accompanying notes to financial statements.

EL PASO ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS
(In thousands)

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Cash Flows From Operating Activities:				
Net income (loss)	$ 41,919	$ 382,471	$ (33,319)	$ (28,153)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:				
Depreciation and amortization	99,355	8,246	69,444	67,189
Deferred income taxes and investment tax credit, net	41,341	(3,116)	(26,744)	(17,990)
Reorganization items, net of income tax benefit	–	(122,251)	–	–
Extraordinary gain on discharge of debt	–	(264,273)	–	–
Gain on sale of investment	(3,844)	–	–	–
Other operating activities	562	(805)	(6,795)	(5,429)
Change in:				
Accounts receivable	3,513	5,429	(4,866)	285
Federal income tax receivable	(20,713)	–	–	–
Inventories	(32)	90	1,590	268
Prepayments and other	(1,974)	34	2,214	(1,056)
Long-term contract receivable	2,333	293	(80)	(1,183)
Obligations subject to compromise	–	9,430	71,839	42,943
Accounts payable	(4,038)	(6,859)	11,885	(14,017)
Interest accrued	23,034	–	–	–
Net overcollection of fuel revenues	(10,784)	417	16,581	23,333
Revenues subject to refund	–	2,785	24,107	11,475
Other current liabilities	(1,242)	(152)	1,027	1,897
Deferred charges and credits	(1,117)	1,994	21,187	13,885
Net cash provided by operating activities	168,313	13,733	148,070	93,447
Cash Flows From Investing Activities (Note B):				
Additions to utility plant	(53,018)	(8,231)	(88,267)	(60,113)
Proceeds from sale of investment	20,183	–	–	–
Investment in decommissioning trust fund	(5,960)	(553)	(5,159)	(5,018)
Other investing activities	(328)	55	330	137
Net cash used for investing activities	(39,123)	(8,729)	(93,096)	(64,994)
Cash Flows From Financing Activities (Note B):				
Proceeds from issuance of preferred stock	–	97,500	–	–
Proceeds from issuance of long-term debt	–	778,120	–	–
Redemption of obligations subject to compromise	–	(1,131,695)	(1,051)	(955)
Repurchase of long-term debt	(117,522)	–	–	–
Principal payments on long-term note payable	(6)	–	–	–
Proceeds from financing and capital lease obligations	17,365	43,309	–	–
Redemption of financing and capital lease obligations	(14,409)	–	–	–
Capital stock expense	(596)	–	–	–
Net cash used for financing activities	(115,168)	(212,766)	(1,051)	(955)
Net increase (decrease) in cash and temporary investments	14,022	(207,762)	53,923	27,498
Cash and temporary investments at beginning of period	54,745	262,507	208,584	181,086
Cash and temporary investments at end of period	$ 68,767	$ 54,745	$ 262,507	$ 208,584
Supplemental Disclosures of Cash Flow Information:				
Cash (refunded) paid for:				
Income taxes	$ (2,504)	$ –	$ 12,950	$ 4,700
Interest	53,000	8,580	80,688	92,474
Reorganization items - professional fees and other	8,682	2,279	15,207	26,406

See accompanying notes to financial statements.

A. Fresh-Start Reporting

On January 8, 1992 (the "Petition Date"), El Paso Electric Company (the "Predecessor Company") filed a voluntary petition for reorganization (the "Bankruptcy Case") under Chapter 11 of the United States Bankruptcy Code (the "Bankruptcy Code") in the United States Bankruptcy Court for the Western District of Texas, Austin Division (the "Bankruptcy Court"). The Bankruptcy Court entered an order dated January 9, 1996 confirming the Company's Fourth Amended Plan of Reorganization (the "Plan"). On February 12, 1996, the Plan became effective (the "Effective Date") and the Company emerged from bankruptcy (the "Reorganization") as an independent investor-owned utility (the "Reorganized Company" or the "Company").

In connection with the emergence from bankruptcy, the Company adopted fresh-start reporting in accordance with the requirements of Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" ("SOP 90-7"). The application of SOP 90-7 resulted in the creation of a new reporting entity having no retained earnings or accumulated deficit. Accordingly, the financial statements of the Reorganized Company for post-bankruptcy periods, which reflect the application of fresh-start reporting, are not comparable to the financial statements of the Predecessor Company.

In applying fresh-start reporting the Company determined its reorganization value which was allocated to the Company's assets and recorded liabilities at their fair values as of the Effective Date. The Company determined its reorganization value by determining the value of its capital structure, exclusive of operational liabilities, based on management's estimates of future operating results. Debt securities and preferred stock were reflected at face value which approximated fair value and common stockholders' equity was valued at $300 million. The value of the capital structure plus operational liabilities equaled reorganization value. Reorganization value necessarily assumes that the Reorganized Company will achieve its estimated future operating results in all material respects. If such results are not achieved, the value of the Reorganized Company could be materially different.

Reorganization value was allocated first to those assets which have readily determinable fair values, such as cash and investments, receivables and inventories, or assets whose historic values generally approximate their fair values. The remaining balance represents the value attributable to the Company's integrated utility system. The Company determined that no value is attributable to identifiable intangible assets. Such intangible assets do not allow the Company to receive values in excess of what would otherwise be obtained. Therefore, the entire remaining balance was allocated to utility plant in service.

The significant effects of the Reorganization and adjustments made in fresh-start reporting resulted in (i) decreased operation expense and increased depreciation expense due to the reacquisition of previously sold and leased back generation facilities and due to accelerated depreciation expense on a portion of the reorganization value assigned to certain plant assets; (ii) increased interest expense due to the changes in the Company's capital structure; and (iii) increased operating revenues related to a rate increase in the Company's Texas jurisdiction.

The effects of the Reorganization and fresh-start reporting on the Company's balance sheet as of February 11, 1996 are as follows (In thousands):

	Predecessor Company February 11, 1996	(a) Reacquisition of Plant	(b) Discharge of Debt	(c) Settlement with Stockholders	(d) Fresh-Start Adjustments	Reorganized Company February 11, 1996
Utility plant:						
Net plant in service	$1,278,617	$ 227,656	$ –	$ –	$ (54,179)	$1,452,094
Construction work in progress	50,793	–	–	–	–	50,793
Net nuclear fuel	42,668	–	–	–	–	42,668
Net utility plant	1,372,078	227,656	–	–	(54,179)	1,545,555
Current assets:						
Cash and temporary investments	266,442	–	(211,697)	–	–	54,745
Accounts receivable	55,362	–	–	–	5,738	61,100
Inventories	32,647	–	–	–	(4,357)	28,290
Prepayments and other	6,753	–	–	–	–	6,753
Total current assets	361,204	–	(211,697)	–	1,381	150,888
Long-term contract receivable	33,390	–	–	–	–	33,390
Deferred charges and other assets:						
Accumulated deferred income taxes	–	–	–	–	115,354	115,354
Decommissioning trust fund	26,736	–	–	–	–	26,736
Other	7,851	–	14,241	–	16,339	38,431
Total deferred charges and other assets	34,587	–	14,241	–	131,693	180,521
Total assets	$1,801,259	$ 227,656	$ (197,456)	$ –	$ 78,895	$1,910,354
Capitalization:						
Common stock	$ –	$ –	$ 255,000	$ 45,000	$ –	$ 300,000
Predecessor common stock	339,097	–	–	(339,097)	–	–
Accumulated earnings (deficit)	(731,431)	(6,783)	264,273	375,561	98,380	–
Net unrealized gain on marketable securities, net of tax	172	–	–	–	(172)	–
Common stock equity (deficit)	(392,162)	(6,783)	519,273	81,464	98,208	300,000
Preferred stock	–	–	100,000	–	–	100,000
Predecessor preferred stock	81,464	–	–	(81,464)	–	–
Obligations subject to compromise	1,645,277	361,597	(2,006,874)	–	–	–
Long-term debt and financing and capital lease obligations	–	–	1,164,328	–	–	1,164,328
Total capitalization	1,334,579	354,814	(223,273)	–	98,208	1,564,328
Current liabilities:						
Current maturities of financing and capital lease obligations	–	–	24,213	–	–	24,213
Accounts payable	41,253	–	–	–	–	41,253
Taxes accrued other than federal income taxes	24,540	–	–	–	(1,591)	22,949
Net overcollection of fuel revenues	13,327	–	(3,255)	–	712	10,784
Other	14,395	–	332	–	(1,960)	12,767
Total current liabilities	93,515	–	21,290	–	(2,839)	111,966
Deferred credits and other liabilities:						
Accumulated deferred income taxes	67,803	–	–	–	(67,803)	–
Accumulated deferred investment tax credits	77,950	–	–	–	(77,950)	–
Deferred gain on sales and leasebacks	127,673	(127,158)	–	–	(515)	–
Decommissioning	48,349	–	–	–	36,582	84,931
Accrued postretirement benefit liability	21,500	–	–	–	52,340	73,840
Accrued pension liability	7,941	–	5,575	–	21,738	35,254
Other	21,949	–	(1,048)	–	19,134	40,035
Total deferred credits and other liabilities	373,165	(127,158)	4,527	–	(16,474)	234,060
Total capitalization and liabilities	$1,801,259	$ 227,656	$ (197,456)	$ –	$ 78,895	$1,910,354

(a) To record, at fair value, the reacquisition of the previously sold and leased-back generation facilities at the Palo Verde Nuclear Generating Station ("Palo Verde") and the recognition of the related allowed claims in excess of the amounts recorded on the Predecessor Company's balance sheet.

(b) To record the settlement with the Predecessor Company's creditors including the issuance of $945.8 million of first mortgage bonds, $100 million of preferred stock, a draw of $43.3 million on the revolving credit facility related to the financing of nuclear fuel, the issuance of $255 million of the Reorganized Company's common stock, and the carry forward of approximately $206 million of pollution control revenue bonds and other miscellaneous claims of the Predecessor Company.

(c) To record the settlement with the previous common and preferred stockholders of the Predecessor Company including the cancellation of the Predecessor Company's common and preferred stock and the issuance of approximately 3% and 12%, respectively, of the Reorganized Company's common stock.

(d) To record the adjustments that allocate the reorganization value to assets and reflect liabilities at their fair values and to adjust the accumulated deficit to zero.

B. Emergence from Bankruptcy

The Reorganization

The Reorganization became effective immediately prior to the consummation of the sale by the Reorganized Company in an underwritten offering of $794 million of first mortgage bonds and $100 million of 11.4% preferred stock. The net proceeds of approximately $875.6 million were distributed to the Predecessor Company's creditors pursuant to the Plan. In addition, the Reorganized Company issued $151.8 million aggregate principal amount of first mortgage bonds and approximately 60 million shares of common stock, and paid approximately $150 million of cash (in addition to the net cash proceeds of the underwritten offering) to holders of allowed claims and interests in the Reorganization. The interest rates on the five series of First Mortgage Bonds range from 7.25% to 9.40% per annum and maturities range from three to fifteen years.

Under the Reorganization, the Predecessor Company's total obligations subject to compromise of $2,007 million (including obligations related to leases on portions of Palo Verde that represented $700 million of allowed claims in the Bankruptcy Case) were extinguished and the creditors received a combination of cash and newly issued debt and equity securities of the Reorganized Company. The discharge of obligations subject to compromise for less than their recorded amounts resulted in an extraordinary nontaxable gain on discharge of debt of $264.3 million. Pursuant to the Plan, all of the Predecessor Company's Common and Preferred Stock was cancelled and the holders of such securities received approximately 15% of the Reorganized Company's Common Stock and the right to receive certain litigation recoveries, if any.

In addition, in connection with the extinguishment of Palo Verde lease obligations on the Effective Date, in accordance with Palo Verde license amendments issued by the United States Nuclear Regulatory Commission, arrangements pursuant to which the Predecessor Company sold and leased back portions of its interest in Palo Verde were terminated and the Reorganized Company reacquired such interests. The Reorganized Company has agreed to indemnify certain parties to the sale/leaseback transactions against possible tax liabilities related thereto. See Note J.

A final order in Docket No. 12700 (the "Agreed Order") was entered on August 30, 1995 by the Public Utility Commission of Texas (the "Texas Commission") and became effective on the Effective Date. The Agreed Order implemented certain provisions of a settlement (the "Rate Stipulation") dated July 27, 1995 among the Company and substantially all of the other parties to Docket No. 12700. Among other things, under the Rate Stipulation (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for ten years beginning August 2, 1995 (the "Freeze Period"); (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vi) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

The Reorganization also provided for many other matters, including the satisfaction or disposition of various types of claims against the Predecessor Company, the assumption of certain leases and agreements, the reconstitution of the board of directors following the Effective Date and the entry into employment and other arrangements with certain members of management.

Reorganization items (expense), net of income tax benefit (expense), recorded by the Predecessor Company consisted of the following (In thousands):

	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Adjustments of assets and liabilities to fair value	$ (92,013)	$ –	$ –
Rate Stipulation	71,579	–	–
Provisions for settlement of claims	(34,317)	–	–
Deferred income tax benefit related to Reorganization	190,393	–	–
Professional fees and other expenses	(14,348)	(19,776)	(15,866)
Interest earned on accumulated cash resulting from Bankruptcy Case, net of income tax expense	957	9,798	6,875
	$ 122,251	$ (9,978)	$ (8,991)

Non-cash investing and financing activities recorded by the Company consisted of the following (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Issuance of preferred stock for pay-in-kind dividend	$ 8,426	$ –	$ –	$ –
Property purchased through issuance of promissory note	964	–	–	–
Reorganized Common Stock exchanged for Predecessor Common and Preferred Stock	–	45,000	–	–
Reorganized Common Stock exchanged for settlement of obligations subject to compromise	–	255,000	–	–
Long-term debt exchanged for settlement of obligations subject to compromise	–	151,834	–	–
Plant in service reacquired through incurring obligation subject to compromise	–	227,656	–	–

C. Rate Matters

Overview

Texas. The rates and services of the Company in Texas municipalities are regulated by those municipalities, and in unincorporated areas by the Texas Commission. The largest municipality in the Company's service area is the City of El Paso. The Texas Commission has exclusive appellate jurisdiction to review municipal orders and ordinances regarding rates and services in Texas and jurisdiction over certain activities of the Company.

New Mexico. The New Mexico Public Utility Commission (the "New Mexico Commission") has jurisdiction over the Company's rates and services in New Mexico and jurisdiction over certain activities of the Company, including prior approval of the issuance, assumption or guarantee of securities. The New Mexico Commission's decisions are subject to judicial review. Current base rates in New Mexico were established in 1990 and have not increased. The Company does not have an agreement with New Mexico regulatory authorities or parties to past New Mexico regulatory proceedings comparable to the Rate Stipulation.

Federal Energy Regulatory Commission. The Company is subject to regulation by the Federal Energy Regulatory Commission (the "FERC") in certain matters, including rates for wholesale power sales, transmission of electric power and the issuance of securities.

Department of Energy. The Department of Energy (the "DOE") traditionally regulates the Company's exports of power to the Comision Federal de Electricidad (the "CFE") in Mexico pursuant to a license granted by the DOE and a presidential permit. In addition, the DOE is authorized to assess operators of nuclear generating facilities for a share of the costs of decommissioning the DOE uranium enrichment facilities over a period of fifteen years.

Nuclear Regulatory Commission. The Nuclear Regulatory Commission (the "NRC") has jurisdiction over the Company's licenses for Palo Verde, regulates the operation of nuclear generating stations to protect the health and safety of the public from radiation hazards and conducts environmental reviews.

Texas Rate Matters

Rate Stipulation and Agreed Order. The Company's rates for its Texas jurisdictional customers are governed by the Agreed Order, which became effective on the Effective Date. The Agreed Order implemented certain provisions of the Rate Stipulation and set rates consistent with the Rate Stipulation. Among other things, under the Rate Stipulation: (i) the Company received a one-time annual increase in Texas retail base rates of approximately $24.9 million; (ii) the Company's base rates for most customers in Texas were fixed at this increased level for the Freeze Period; (iii) the City of El Paso granted the Company a new franchise that extends through the Freeze Period; (iv) the Company will retain 75% during the first five years of the Freeze Period and 50% during the remainder of the Freeze Period of (A) the revenues generated by providing third-party transmission services and (B) profit margins from certain off-system power sales; (v) the Company's reacquisition of the Palo Verde leased assets is deemed to be in the public interest; (vi) no refunds or surcharges were made to customers with respect to fuel costs and revenues for the period from July 1993 through June 1995; and (vii) all appeals of Texas Commission orders concerning the Company and all outstanding Texas Commission dockets concerning the Company's rates were resolved.

Neither the Rate Stipulation nor the Agreed Order deprives the Texas regulatory authorities of their jurisdiction over the Company during the Freeze Period. However, the Texas Commission determined in the Agreed Order that the rate freeze is in the public interest and results in just and reasonable rates. Further, the signatories to the Rate Stipulation (other than the General Counsel, OPC and the State of Texas) agreed not to seek to initiate an inquiry into the reasonableness of the Company's rates during the Freeze Period and to support the Company's entitlement to rates at the freeze level throughout the Freeze Period. The Company believes, but cannot assure, that its cost of service will support rates at or above the freeze level throughout the Freeze Period and, therefore, does not believe any attempt to reduce the Company's rates would be successful. However, during the Freeze Period, the Company is precluded from seeking rate increases in Texas, even in the event of increased operating or capital costs. In the event of a merger, the parties to the Rate Stipulation retain all rights provided in the Rate Stipulation, their rights to participate as a party in any proceeding related to the merger, as well as the right to pursue a reduction in rates below the freeze level to the extent of post-merger synergy savings. See "Recent Changes in Utility Regulation."

Fuel. The Company must periodically reconcile its Texas fuel costs pursuant to Texas Commission rules. The Company has not filed a reconciliation, which must contain not less than twelve months nor more than thirty-six months of reconcilable data for any period since June 1995. In a reconciliation, revenues that the Company collected from Texas customers under its fixed fuel factor are reconciled with the expenses for fuel and purchased power actually incurred by the Company for the period covered by the reconciliation. Differences between revenues collected and expenses incurred are subject to a refund to customers (in the case of an overrecovery of fuel costs) or surcharge (in the case of an underrecovery of fuel costs). The Commission staff, local regulatory authorities such as the City of El Paso, and customers are entitled to intervene in a fuel reconciliation proceeding and to challenge the recovery of expenses on the basis of unreasonable or improper fuel and purchased power costs.

Higher natural gas prices began in December 1996 and continued in the first quarter of 1997. These higher natural gas prices will increase the Company's underrecovered fuel costs, which will be reviewed in the next Texas fuel reconciliation.

Palo Verde Performance Standards. The Texas Commission has established performance standards for the operation of Palo Verde, pursuant to which Palo Verde is evaluated annually to determine whether its three-year rolling average capacity factor entitles the Company to a reward or subjects it to a penalty. There are five performance bands based around a target capacity factor of 70%. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the capacity factor, as measured on a station-wide basis for any consecutive 24-month period, should fall below 35%, the Texas Commission could reconsider the rate treatment of Palo Verde, regardless of the provisions of the Rate Stipulation. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. Based upon the formula for calculating the performance standards in Texas, the Company does not believe a performance penalty will be assessed for the year ended December 31, 1996.

New Mexico Rate Matters

Pending Rate Case. In October 1996, the New Mexico Commission issued an order in Case No. 2722, requiring the Company to answer certain ratepayer complaints and to file a rate filing package, including cost of service data and supporting testimony. On March 3, 1997, the Company filed all of the rate filing package data required by the Commission's order with the Commission. Although the Company's filing demonstrates a revenue deficiency of approximately $8.6 million under current rates, the Company did not request a rate change to recover the deficiency. The Company cannot predict what action the New Mexico Commission may take in this proceeding.

Fuel. The Company is required to file an annual fuel report and an annual Palo Verde performance standards report, discussed below, with the New Mexico Commission by January 31 of each year for the preceding calendar year. The Company requested and received two extensions of time and filed these reports on March 24, 1997. The Company's filing reflects a significant increase in the monthly fuel charge to be effective with bills rendered on or after May 1, 1997. This increase is necessary because of significant increases in the spot price of natural gas which have caused the Company to underrecover its fuel costs in New Mexico by approximately $2.0 million for the year ended December 31, 1996. The recovery of this amount, coupled with projected higher gas costs for 1997, results in an increase in the proposed 1997 fuel factor of approximately 50% over the present factor. There can be no assurance that the Commission will accept the Company's proposed fuel factor. As in Texas, interested parties are allowed to intervene and challenge the recoverability of expenses as unreasonable or imprudent. Any significant disallowance of recovery could have a material adverse effect on the Company's financial results.

Palo Verde Performance Standards. The New Mexico Commission has established performance standards for the operation of Palo Verde, pursuant to which the entire Palo Verde station is evaluated annually to determine if its achieved capacity factor allows the Company to claim a credit or subjects the Company to a penalty. Because Unit 3 is not included in the Company's New Mexico rate base, any penalty or credit calculated on a total station basis is limited to two-thirds of such penalty or credit. The capacity factor is calculated as the ratio of actual generation to maximum possible generation. If the annual capacity factor is 35% or less, the New Mexico Commission is required to initiate a proceeding to reconsider the rate base treatment of Palo Verde. The removal of Palo Verde from rate base could have a significant negative impact on the Company's revenues and financial condition. For the year ended December 31, 1996, the Palo Verde station capacity factor was 86.20%. This capacity factor resulted in the Company's entitlement to a credit. However, the Company is voluntarily foregoing collection of this credit to partially mitigate the increase in the proposed New Mexico fuel factor, discussed above.

Federal Regulatory Matters

FERC. The Company has a long-term firm power sales agreement with IID providing for the sale of 100 MW of firm capacity and 50 MW of contingent capacity through April 2002. The agreement generally provides for level sales prices over the life of the agreement. The Company has a firm power sales agreement with TNP, providing for sales to TNP in the minimum amount of 25 MW through 2002. Sales prices are essentially level for the remaining life of the agreement. Rate tariffs currently applicable to IID and TNP contain fuel and purchased power cost adjustment provisions designed to recover the Company's fuel and purchased power costs.

In July 1996, the Company filed its open access transmission tariffs (Docket No. OA96-200-000) in compliance with Order No. 888, *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities* ("Order No. 888"), covering network and point-to-point transmission services and the six specifically required ancillary services. Several parties, including Las Cruces, other utilities and several wholesale power marketers intervened and filed protests to the Company's tariffs. Issues raised by the intervenors included rates and the terms and conditions of the Company's tariffs, including the treatment and costs related to certain facilities making access to the CFE more available to parties other than the Company. In February 1997, the Company entered into a stipulated agreement among the various parties settling all issues related to Docket No. OA96-200-000. Under the settlement the Company will provide transmission service, to the extent transmission capacity is available, to any party for firm or interruptible service to the CFE until the earlier of the end of 1998 or the date the FERC rules on the complaint filed by Enron. See Note K.

In December 1996, Las Cruces filed a request at the FERC for a determination that Las Cruces would have no stranded cost obligation to the Company in the event the city leaves the Company's system and operates its own municipal utility. The Company calculated Las Cruces' stranded cost obligation to be approximately $234 million. The FERC is expected to establish a procedural schedule for discovery and hearings in this matter. The Company is unable to predict the outcome of this proceeding or the impact it may have on the Company. See Note K.

Also in December 1996, Southwestern Public Service Company ("SPS") filed a request for the issuance of an order by the FERC requiring the Company to accept as a "completed application" for service under the Company's open access transmission tariff a September 1996 request by SPS for service that may be needed for SPS to deliver electricity to a newly-formed Las Cruces municipal electric system. The Company stated in response to that request that SPS had failed to provide certain information required to be submitted by persons seeking service under its open access transmission tariff. The Company has asked that the proceedings initiated by Las Cruces and by SPS, respectively, be consolidated. Both matters are currently pending before the FERC.

Department of Energy. In October 1996, the FERC issued an order requiring the Company to provide Enron Power Marketing, Inc., a wholesale power marketer, with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction.

Promptly after the issuance of the FERC order, Enron asked the DOE to exercise its authority over Presidential Permits relating to construction of border-crossing transmission facilities and over export authorizations issued to the Company and to Enron to require transmission access for delivery of electricity to the CFE in Mexico. Pursuant to Enron's request, the DOE, on October 30, 1996, issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties with respect to Presidential Permits and export authorizations issued to the Company. The Company has filed responses to Enron's request at both the FERC and the DOE in which it has asserted that the DOE has no authority to require transmission of electric energy for delivery to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder during 1997, if someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position, which remains that under the current law the provision of such access is not required. Neither the FERC nor the DOE has taken any final action on this matter.

Other Wholesale Customers

The primary term of the Company's previous five year sales agreement for firm capacity and associated energy to the CFE terminated December 31, 1996. In September 1996, the CFE issued a request for proposals for replacement power for 1997. The Company submitted a bid and was ultimately selected by the CFE to provide varying amounts of power during 1997 ranging from 120 to 200 MW. Since the CFE load provided by the Company will be isolated from the rest of the CFE system, the Company is also providing the CFE with the flexibility to increase its power deliveries up to 5% above its monthly contract capacity level in order to meet its customer power requirements. The price is stable throughout the term of the agreement and includes charges for capacity and energy as well as transmission and any required ancillary services. Under the new agreement with the CFE, revenues in 1997 related to power sales to the CFE are expected to be lower than revenues recorded in 1996. The agreement requires payment in United States dollars. See Notes K and M.

Recent Changes in Utility Regulation

General. The electric utility industry faces increasing pressure to become more competitive as legislative, regulatory, economic and technological changes occur. Federal legislation, as well as legislative and regulatory initiatives in various states and proposed initiatives in Texas and New Mexico, encourages competition in the Company's service area for electricity generation among electric utility and non-utility power producers. Together with increasing customer demand for lower-priced electricity and other energy services, these measures have accelerated the industry's movement toward more competitive pricing and cost structures. Such competitive pressures could result in the loss of customers and diminish the ability of the Company to fully recover its investment in generation assets, as well as the cost of operating these assets. This issue is particularly important to the Company because its rates are significantly higher than the national and regional averages. In the face of increased competition, there can be no assurance that such competition will not adversely affect the future operations, cash flows and financial condition of the Company, or that the Company will be able to sustain retail rates at the levels established by the Rate Stipulation during the Freeze Period.

Of particular importance to the Company is the issue of ultimate recoverability of costs previously found by regulatory authorities to be reasonable and prudent, but which at the same time are higher than would be recovered under immediate, full competition (i.e., stranded costs). Across the industry, as well as at the state level, there is much discussion and debate on this issue. At this time, there appears to be no clear solution. At the federal level, the FERC has announced, through a formal rulemaking, its intention to allow 100% recovery of all legitimate verifiable stranded costs attributable to FERC jurisdictional customers. Texas and New Mexico are engaged in various activities, at the commission and legislative level, which are attempting to address the issue of stranded cost recovery from customers subject to state legislation.

FERC. In April 1996, pursuant to its authority under Sections 205 and 206 of the FPA, the FERC issued its Order No. 888. Order No. 888 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to (i) file open access transmission tariffs containing minimum terms and conditions of non-discriminatory service and (ii) take transmission service (including ancillary services) for their own new wholesale sales and purchases of electric energy under the open access tariffs. Additionally, Order No. 888 permits public utilities to seek recovery of legitimate, prudent and verifiable stranded costs and provides a mechanism for the recovery of such costs. Order No. 888 also provides for recovery of costs associated with former power customers and new municipally-owned entities becoming transmission-only customers as a result of providing open access transmission if the utility had a reasonable expectation of continuing to provide service to the departing customer. Order No. 888

established criteria under which stranded costs will be evaluated for contracts entered into prior to July 11, 1994, and for stranded costs resulting from the formation of any new municipal utilities. Recovery of stranded costs under contracts entered into after July 10, 1994, will be governed by the terms of those contracts.

In April 1996, the FERC also issued Order No. 889, *Open Access Same-Time Information System (formerly Real-Time Information Networks) and Standards of Conduct* ("Order No. 889"). Order No. 889 requires all public utilities owning, operating or controlling facilities used for transmitting electricity in interstate commerce to develop and maintain an Open Access Same-Time Information System that will give existing and potential transmission users access to transmission related information on a basis consistent with that available to a utility's employees engaged in the buying and selling of power. Order No. 889 further requires public utilities to separate their transmission and generation marketing functions and communications and adopt standards of conduct ensuring that all open access transmission customers are treated in a non-discriminatory manner.

Texas. In February 1996, the Texas Commission adopted a rule governing wholesale transmission access, as required by recent Texas legislation. The Texas Commission does not have jurisdiction over the Company's wholesale transactions. However, the rule required the Company to file its FERC-approved open access transmission tariffs with the Texas Commission to certify compliance with the Texas legislation.

During 1996, pursuant to the directives of the Texas Legislature in legislation passed in 1995, the Texas Commission conducted projects to evaluate the (i) scope of competition in the electric industry in Texas and (ii) potential for stranded investment, procedures for allocating stranded costs and acceptable methods of stranded cost recovery. The Texas Commission's report consolidating the two projects was issued in January 1997. While it recommended a careful and deliberate approach to continued expansion of competition in the Texas electric market, ultimately leading to retail competition with certain safeguards, it also recommended against any legislation that would introduce broad based retail competition before 2000. The Texas Commission quantified the potential "excess of cost over market" ("ECOM") at both wholesale and retail levels under several scenarios. With respect to the Company's potential for stranded costs, the Texas Commission estimated no wholesale ECOM, and estimated retail ECOM ranging from a high of $1.3 billion to a low of $781.0 million, with an expected value of $1.1 billion, assuming full retail access in 1998. The Company cannot determine at this time the effects that would occur, including any possible effects on the Rate Stipulation, as the result of any broad based competition legislative action, if any, implemented in 1997.

New Mexico. The New Mexico Commission initiated a notice of inquiry regarding competition and the restructuring of regulation of the electric industry in 1996. The New Mexico Commission received comments from numerous parties representing various interests and conducted workshops in an attempt to arrive at a consensus with respect to the need for regulatory change, the nature of such change and the timing/transition of any changes. No consensus was reached by the participants. With respect to stranded costs, the New Mexico Commission applied the same ECOM model that was developed for Texas. The Company's New Mexico ECOM calculation ranged from a high of $248 million to a low of $173 million. The Company also provided the New Mexico Commission with its calculation of stranded costs for New Mexico pursuant to FERC Order No. 888, which equaled $364 million.

D. Summary of Significant Accounting Policies

General. The Company is a public utility engaged in the generation, transmission and distribution of electricity in an area of approximately 10,000 square miles in west Texas and southern New Mexico. As of December 31, 1996, the Company served approximately 279,000 residential, commercial, industrial and wholesale customers. The Company distributes electricity to retail customers principally in El Paso, Texas and Las Cruces, New Mexico. The Company also serves wholesale customers in Texas, New Mexico, California and Juarez, Mexico..

The preparation of financial statements in conformity with generally accepted accounting principles 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.

The Company maintains its accounts in accordance with the Uniform System of Accounts prescribed for electric utilities by the FERC. Prior to December 31, 1991, the Company reported its regulated utility operations pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS No. 71"). The Company discontinued the application of SFAS No. 71 as of December 31, 1991.

As more fully discussed in Note A, the Company emerged from bankruptcy on February 12, 1996. The Company has accounted for all transactions related to the reorganization proceedings in accordance with SOP 90-7. The Reorganization had significant impacts on the financial statements of the Reorganized Company, including the creation of a new reporting entity upon emergence from bankruptcy through the application of fresh-start reporting pursuant to SOP 90-7. Accordingly, the Company's post-Reorganization balance sheets and the statement of operations, which reflect the application of fresh-start reporting, have not been prepared on a consistent basis with the pre-Reorganization financial statements and are not comparable in all respects to the financial statements prior to the Reorganization. For accounting purposes, the inception date of the Reorganized Company is deemed to be February 12, 1996. A vertical line is shown in the financial statements to separate the Reorganized Company from the Predecessor Company, since the financial statements have not been prepared on a consistent basis of accounting.

Utility Plant. As a result of adopting fresh-start reporting, as discussed in Note A, the Company has revalued its utility plant. As of February 12, 1996, the value allocated to the assets used in the Company's generation, transmission and distribution operations is based on the Company's estimate of the replacement cost less depreciation ("RCLD") and is derived from the value of the Company as a going concern rather than on an appraisal or other professional valuation of its assets. The RCLD of generation assets was calculated based on estimates of the current cost of gas-fired combined-cycle and combustion turbine power plants, adjusted for certain economic factors. Depreciation is provided on a straight-line basis over the estimated remaining lives of the assets (ranging from 11 years to 31 years), except for approximately $384 million of reorganization value allocated to net transmission, distribution and general plant in service. This amount is being depreciated over the ten-year period of the Rate Stipulation.

NOTES TO FINANCIAL STATEMENTS

Prior to February 12, 1996, utility plant was stated at original cost, less regulatory disallowances. Costs included labor, material, construction overheads, and allowance for funds used during construction ("AFUDC") or capitalized interest (see Capitalized Interest below). Depreciation was provided on a straight-line basis at annual rates which amortized the undepreciated cost of depreciable property over the estimated remaining service lives, which ranged from 3 years to 49 years. Palo Verde was being amortized on a straight-line basis over approximately 40 years.

The Company charges the cost of repairs and minor replacements to the appropriate operating expense accounts and capitalizes the cost of renewals and betterments. Gains or losses resulting from retirements or other dispositions of operating property in the normal course of business are credited or charged to the accumulated provision for depreciation.

In connection with the emergence from bankruptcy, the Company accrued a liability for the present value of the estimated decommissioning costs for the Company's interest in Palo Verde. Accretion of the decommissioning liability is charged to interest charges in the statement of operations.

The cost of nuclear fuel is amortized to fuel expense on a unit-of-production basis. A provision for spent fuel disposal costs is charged to expense based on requirements of the DOE for disposal cost of one-tenth of one cent on each kilowatt hour generated.

Capitalized Interest. As a result of discontinuation of the application of SFAS No. 71, the Company discontinued accruing AFUDC in 1992. In place of AFUDC, the Company capitalizes to construction work in progress ("CWIP") and nuclear fuel in process interest cost calculated in accordance with SFAS No. 34, "Capitalization of Interest Cost."

Cash and Cash Equivalents. All temporary cash investments with an original maturity of three months or less are considered cash equivalents.

Investments. The Company's marketable securities, included in decommissioning trust funds in the balance sheets, are reported at fair market value and consist primarily of municipal bonds in trust funds established for decommissioning of its interest in Palo Verde which have a fair market value of approximately $33.1 million at December 31, 1996. Such marketable securities are classified as "available-for-sale" securities and as such the difference between cost and market value is shown as a separate component of capitalization.

Inventories. Inventories, primarily parts, materials and supplies, are stated at average cost not to exceed recoverable costs.

Operating Revenues. The Company accrues revenues for services rendered but unbilled.

The regulations of the Texas Commission, New Mexico Commission and FERC and the agreements with individual customers generally provide for fuel and purchased and interchanged power expenses to be recovered from customers. Fuel revenues reflect the Company's estimate of recoverable fuel and purchased and interchanged power expenses net of a percentage of (i) profit margins from certain off-system sales and

(ii) revenues from third party transmission services, which is credited to customers. Economy sales relate to spot market sales and is included in fuel revenues. Base revenues refer to the Company's revenues from the sale of electricity excluding such fuel revenues.

Federal Income Taxes. The Company accounts for federal income taxes under SFAS No. 109, which requires the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred income taxes are recognized for the estimated future tax consequences of "temporary differences" by applying enacted statutory tax rates for each taxable jurisdiction applicable to future years to differences between the financial statement carrying amounts and the tax bases of existing assets and liabilities. SFAS No. 109 requires the Company to record a valuation allowance to reduce its deferred tax assets to the extent it is more likely than not that such deferred tax assets will not be realized. SFAS No. 109 recognizes the effect on deferred tax assets and liabilities of a change in tax rate in income in the period that includes the enactment date.

Benefit Plans. See Note L for accounting policies regarding the Company's retirement plans and postretirement benefits.

Earnings per Share. Earnings (loss) per common share is computed by dividing net income or loss, after deducting the preferred dividend requirements, by the weighted average number of common shares and dilutive common share equivalents outstanding.

For the Reorganized Company, for the period February 12 through December 31, 1996, the computation of fully-diluted earnings per share was immaterially different from primary earnings per share.

For the Predecessor Company, there was no difference between primary and fully-diluted earnings per share.

Stock Option Plans. The Company has an option plan which reserves shares of common stock for issuance to officers. The Company has adopted the disclosure-only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, compensation cost is recognized for the intrinsic value, if any, of option grants at measurement date ratably over the vesting period of the options.

Impairment of Long-Lived Assets. The Company adopted the provisions of SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," upon the emergence from bankruptcy. SFAS No. 121 requires that long-lived assets and certain identifiable intangibles be 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. The Company's application of fresh-start reporting upon the emergence from bankruptcy encompassed the adoption of SFAS No. 121 and as such the Company's adoption of SFAS No. 121 did not have a significant impact on its financial statements.

Reclassifications. Certain amounts in the financial statements for 1995 and 1994 have been reclassified to conform with the 1996 presentation.

E. Palo Verde and Other Jointly Owned Utility Plant

The Company has a 15.8% undivided interest in the three 1,270 MW nuclear generating units at Palo Verde in which six other utilities (collectively, the "Palo Verde Participants") have interests, including Arizona Public Service Company ("APS"), who is the operating agent of Palo Verde. The operation of Palo Verde and the relationship among the Palo Verde Participants is governed by the ANPP Participation Agreement.

Pursuant to the Plan, the Predecessor Company's Palo Verde lease obligations were extinguished on the Effective Date and the Reorganized Company reacquired the previously sold and leased back portions of Palo Verde. In accordance with fresh-start reporting the Reorganized Company recorded the reacquired portions of Palo Verde at fair market value, which was approximately $227.7 million and revalued the Company's interest in Palo Verde at RCLD. See Note A and the Utility Plant portion of Note D for a discussion of the valuation of the Company's utility plant. As of December 31, 1995, the Company's investment, at cost, in Palo Verde in the amount of approximately $963.0 million, excludes amounts related to the Company's investment in Palo Verde which was sold and leased back during 1986 and 1987 and for which the related leases were accounted for as operating leases.

Other jointly owned utility plant includes a 7% undivided interest in Units 4 and 5 of the Four Corners Project ("Four Corners") and certain other transmission facilities. A summary of the Company's investment in jointly owned utility plant, excluding fuel, at December 31, 1996 and 1995 is as follows (In thousands):

	Reorganized Company December 31, 1996		Predecessor Company December 31, 1995	
	Palo Verde Station	Other	Palo Verde Station	Other
Electric plant in service	$ 568,957	$ 173,409	$ 952,310	$ 135,400
Accumulated depreciation	(22,162)	(10,607)	(155,749)	(59,398)
Construction work in progress	8,545	985	10,653	1,661

Pursuant to the ANPP Participation Agreement, the Palo Verde Participants share costs and generating entitlements in the same proportion as their percentage interests in the generating units and each Palo Verde Participant is required to fund its proportionate share of fuel, other operation, maintenance and capital costs, which, except capital costs, are included in the corresponding expense captions in the statements of operations. The Company's total monthly share of these costs was approximately $6.9 million in 1996. The ANPP Participation Agreement provides that if a participant fails to meet its payment obligations, each non-defaulting participant shall pay its proportionate share of the payments owed by the defaulting participant.

Decommissioning. Prior to Reorganization, the Predecessor Company was accruing its estimated decommissioning obligation over the remaining service life (approximately 40 years) for the portion of its owned interest in Palo Verde and over the term of the related leases (27 to 29 years) for the portions of Palo Verde that were sold and leased back. Upon the adoption of fresh-start reporting, the Company recorded the net present value of estimated future expenditures for decommissioning, using a risk free rate of return of 6.00%, and began accruing interest on the decommissioning liability. The Reorganized Company's interest expense includes approximately $4.6 million related to the accretion of the nuclear decommissioning liability. As of December 31, 1996, the Company has accrued a liability of approximately $89.5 million for its estimated decommissioning costs.

In December 1995, the Palo Verde Participants approved a study by an outside engineering firm of the cost of decommissioning Palo Verde. The 1995 study determined that the Company will have to fund approximately $229 million (stated in 1995 dollars) to cover its share of such costs beginning in 2024 through 2037. The 1995 study assumes that (i) maintenance expense for spent fuel storage will be incurred for ten years after the shutdown of the last unit (estimated to be in 2024) rather than the approximately 30 years utilized in a 1993 study; (ii) a national interim spent fuel storage facility will be available; and (iii) as a result of such national spent fuel storage facility, the amount of spent fuel stored on-site is reduced from all spent fuel assemblies to the final core plus fuel assemblies from approximately three refuelings.

Cost estimates for decommissioning have increased with each study, although the 1995 cost estimate is comparable to the previous cost estimate from a 1993 study (which determined that the Company would have to fund approximately $221 million, stated in 1993 dollars). The 1993 study was based on different assumptions, primarily related to the decommissioning of spent fuel. The 1993 cost estimate included an estimated cost of approximately $50 million related to on-site spent fuel storage facilities, while the 1995 study includes an estimated cost of approximately $13 million related to spent fuel. This difference in estimates is primarily due to the different timing assumptions discussed above. The 1993 estimate reflected an 84% increase from the previous estimate made in 1989, primarily due to an increase in the estimated costs associated with the permanent burial of low-level radioactive waste due to the uncertainty surrounding the availability and cost of low-level radioactive waste repositories, as discussed below.

Although the 1995 study is based on the latest available information, there can be no assurance that decommissioning cost estimates will not continue to increase in the future or that regulatory requirements will not change. In addition, until a new low-level radioactive waste repository opens and operates for a number of years, estimates of the cost to dispose of low-level radioactive waste may increase significantly.

The rate freeze under the Rate Stipulation would preclude the Company from seeking a rate increase in Texas during the Freeze Period to recover increases in decommissioning cost estimates. Additionally, there can be no assurance that the Company could increase its rates in any of its other jurisdictions to recover such increased costs.

The Company has established external trusts with independent trustees, which enable the Company to record a current deduction for federal income tax purposes of a portion of amounts funded. As of December 31, 1996, the aggregate balance of the trust funds was approximately $33.1 million, which is reflected in the Company's balance sheets in deferred charges and other assets.

An industry-wide assessment has been made for decontamination of the DOE's enrichment facilities. The total amount of this assessment has not yet been finalized; however, APS estimates that the annual assessment for Palo Verde will be approximately $3.0 million, plus increases for inflation, for the next fifteen years. The Company has accrued $5.3 million which represents the present value of its remaining portion of the estimated total assessment.

Steam Generators: Palo Verde has experienced degradation in the steam generator tubes of each unit. The degradation includes axial tube cracking in the upper regions of the two steam generators in Unit 2 and, to a lesser degree, in Units 1 and 3. This form of steam generator tube degradation has recently been seen at other U.S. nuclear generating stations. The units also have experienced circumferential cracking at the tube sheet, a more common type of tube cracking. The axial tube cracking was discovered following a steam generator tube rupture in Unit 2 in March 1993. Since that time, APS has undertaken an ongoing investigation and analysis and has performed corrective actions designed to mitigate further degradation. Corrective actions have included changes in operational procedures designed to lower the operating temperatures of the units, chemical cleaning and the implementation of other technical improvements. APS has stated that it believes its remedial actions have slowed the rate of tube degradation.

Each of the Palo Verde units has been inspected during regularly scheduled refueling outages and mid-cycle inspection outages. If tube cracks are detected during an inspection, the affected tubes are taken out of service by plugging. This may impair the performance of a unit if sufficient numbers of steam generator tubes are affected.

The projected service lives of the units' steam generators are reassessed by APS periodically in conjunction with inspections made during outages of the Palo Verde units. In August 1995, APS announced that its ongoing analyses indicated that it will be economically desirable to replace the Unit 2 steam generators, which have been the most affected by tube cracking, in four to nine years. APS further stated that it expects replacement of the steam generators will be performed in conjunction with a normal refueling outage to limit incremental outage time. APS also has stated that, based on the latest available data, it estimates that the steam generators in Units 1 and 3 should operate for their designated life of 40 years (to 2025 and 2027, respectively). APS will continue to assess these steam generators periodically.

Steam generator replacement could be done through new steam generators manufactured for Palo Verde or through the purchase of existing steam generators that are compatible with Palo Verde's design. The Company believes replacement of the steam generators would require the unanimous approval of the Palo Verde Participants. The Company has not yet completed its analysis of the economic feasibility of steam generator replacement, or other options that may be available in connection with the operation of Unit 2. Also, the Company cannot predict whether it or other Palo Verde Participants will agree to replace the Unit 2 steam generators. The Company expects that if the steam generators in Unit 2 are replaced, most of such costs would be incurred between 1998 and 2005. The Company's portion of total costs associated with replacement of the Unit 2 steam generators, including replacement power costs, is currently estimated not to exceed $30 million.

The Rate Stipulation, however, precludes the Company from seeking a rate increase in Texas during the Freeze Period to recover capital costs associated with such replacement should it be necessary.

It is uncertain whether the costs associated with replacing the Unit 2 steam generators would be approved by the New Mexico Commission and included in the Company's rate base in New Mexico.

Liability and Insurance Matters. The Palo Verde Participants have public liability insurance against nuclear energy hazards up to the full limit of liability of $200 million under federal law in the form of primary liability insurance provided by commercial insurance carriers. Additionally, the Company participates in an industry-wide retrospective assessment program, under which industry participants would be required to pay an assessment to cover any loss in excess of $200 million. The maximum assessment per reactor for each nuclear incident is approximately $79.2 million, subject to an annual limit of $10 million per incident. Based upon the Company's 15.8% interest in Palo Verde, the Company's maximum potential assessment per incident is approximately $37.6 million, with an annual payment limitation of approximately $4.7 million.

The Palo Verde Participants maintain "all risk" (including nuclear hazards) insurance for property damage to, and decontamination of, property at Palo Verde in the aggregate amount of $2.7 billion, a substantial portion of the proceeds of which must first be applied to stabilization and decontamination. Finally, the Company has insurance against a portion of any increased cost of generation or purchased power which may result from the accidental outage of any of the three Palo Verde units if the outage exceeds 21 weeks.

F. Common Stock

Overview

The Company issued 60 million shares of new common stock on February 12, 1996. The Common Stock has a stated value of $1 per share, with no cumulative voting rights or preemptive rights. Holders of the Common Stock have the right to elect the Company's directors and to vote on other matters.

The Company's ability to pay dividends on the Common Stock for the next several years will be limited by the terms of applicable laws and financing arrangements entered into pursuant to the Reorganization. All distributions with respect to the Common Stock, including the declaration or payment of dividends, are subject to the provisions of the Texas Business Corporation Act, including provisions that prohibit any distribution that exceeds the surplus of the Company. In addition, under Section 305 of the Federal Power Act, it is unlawful for a director or officer of the Company to participate in the making or payment of dividends from "any funds properly included in capital account." As a result of Reorganization, the Company's first priority at this time is debt retirement and deleveraging as opposed to paying dividends.

Pursuant to the resolutions creating the Series A Preferred Stock, no dividends can be paid on the Common Stock if there are dividends in arrears on the Series A Preferred Stock. So long as the Company's First Mortgage Bonds, Series A through H, are outstanding and the series with the longest maturity is not rated "investment grade" by either Standard & Poor's Rating Service or Moody's Investors Service, Inc., the Company may not declare any dividend on the Common Stock, other than in additional shares of common stock, or make any other distribution on, or acquire for value any shares of common stock (with certain limited exceptions) unless, after giving effect thereto, the aggregate of all such dividends, distributions and certain other payments made by the Company since February 12, 1996 would be less than the sum of (i) 50% of the consolidated net income (as defined in the mortgage indenture) of the Company minus dividends paid in respect of the Series A Preferred Stock for the period from February 13, 1996 to the most recently ended fiscal quarter for which quarterly financial statements are available (or, if such consolidated net income is a deficit, less 100% of such deficit), plus (ii) 100% of the aggregate net proceeds received by the Company from the issuance or sale since February 12, 1996 of equity securities or debt securities that have been converted into equity securities, plus (iii) $10.0 million. Currently, the Company's First Mortgage Bonds are not rated investment grade.

Pursuant to the terms of the reimbursement agreements related to four letters of credit issued in respect of the four series of pollution control revenue bonds, so long as a drawing is available under any of the letters of credit, the same limitation on the declaration of dividends would apply to the Company. In addition to the restriction contained in the mortgage indenture, the reimbursement agreements limit to $15.0 million the aggregate amount of dividends that can be paid on the Common Stock during the three years after its initial issuance on February 12, 1996. The credit agreement for the working capital and fuel financing facility contains the same limitations on the payment of Common Stock dividends as the reimbursement agreements related to the letters of credit on the pollution control revenue bonds.

1996 Long-Term Incentive Plan

The 1996 Long-Term Incentive Plan (the "1996 Plan") authorized the issuance of up to 3,500,000 shares of common stock for the benefit of officers, key employees and non-employee directors through the award or grant of non-statutory stock options, incentive stock options, stock appreciation rights, restricted stock, bonus stock and performance stock. During 1996, the Company granted options covering 1,900,000 shares and awarded 180,000 restricted shares under the 1996 Plan.

Stock Option Plans. At December 31, 1996, options were outstanding for the purchase of 1,900,000 shares of common stock of which 660,000 were exercisable as of December 31, 1996. No options were exercised in 1996. All options expire five years from the date of grant unless terminated earlier by the Board of Directors.

The Company has adopted the disclosure-only provisions of Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). Accordingly, because the stock option grants had no intrinsic value at the measurement date, no compensation cost has been recognized. Had compensation cost for the plan been determined based on the fair value at the grant date for the awards in 1996 consistent with the provisions of SFAS No. 123, the Company's net earnings and earnings per share would have been reduced to the pro forma amounts presented below:

	Period From February 12 to December 31, 1996
Net income applicable to common stock (In thousands):	
As reported	$ 31,431
Pro forma	30,262
Earnings per share:	
As reported	$ 0.52
Pro forma	0.50

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option-pricing model with the following weighted-average assumptions: (i) risk-free rate of return is 6.65% for options awarded April 30, 1996 and 6.99% for options awarded June 11, 1996; and (ii) volatility is 4.09% for options awarded on the April grant date and 4.35% for options awarded on the June grant date, calculated using the standard deviation of the Company's Common Stock from February 16, 1996 to the award date. The weighted-average grant-date fair value of options granted during the year was $2.60 per option. The exercise price is the market price on the date of award, which was $5.32 for 800,000 shares on the April grant date and $5.56 for 800,000 shares on the June grant date, except for 300,000 options awarded to the former Chief Executive Officer ("CEO") of the Company with an exercise price of $7.00. All options vest over a period of five years from the date of grant, subject to earlier vesting in accordance with the current CEO's employment agreement, and except for options awarded the former CEO which were fully vested on the date of grant.

Restricted Shares. At December 31, 1996, 180,000 shares of restricted stock were awarded under the 1996 Plan. Restrictions from resale on 20,000 shares have lapsed as of January 1, 1997.

The value of restricted shares is calculated by multiplying (i) 55,000 shares at $5.00 per share for shares awarded February 12, 1996; (ii) 100,000 shares at $5.32 per share for shares awarded on the April grant date; and (iii) 25,000 shares at $5.63 per share for shares awarded May 1, 1996. Restrictions from resale will lapse over five years beginning December 31, 1996, except for 25,000 shares which restrictions will lapse on May 1, 1997.

Unearned compensation was charged for the value of the restricted shares as these shares were issued in accordance with the 1996 Plan. The unearned compensation is shown as a reduction of common stock equity in the accompanying balance sheet and is being amortized ratably over the restricted period. During 1996, approximately $0.2 million relating to restricted stock was charged to expense.

The holder of a restricted stock award will have rights as a shareholder of the Company, including the right to vote and, if applicable, receive cash dividends on restricted stock, except that certain restricted stock awards require any cash dividend on restricted stock to be delivered to the Company in exchange for additional shares of restricted stock of equivalent market value.

Changes in common stock are as follows:

	Common Stock Shares	Common Stock	Capital in Excess of Stated Value	Unearned Compensation-Restricted Stock Awards
			(In thousands)	
Balance December 31, 1993, 1994 and 1995	35,544,330	$ 339,097	$ –	$ –
Redemption of Predecessor Common Stock	(35,544,330)	(339,097)	–	–
Issuance of Reorganized Common Stock	59,999,981	60,000	240,000	–
Restricted shares	180,000	180	768	(948)
Restricted stock compensation accrued	–	–	–	190
Balance December 31, 1996	60,179,981	$ 60,180	$ 240,768	$ (758)

G. Preferred Stock

The Company issued one million shares of new preferred stock on February 12, 1996. The Preferred Stock has a liquidation preference of $100 per share, has no sinking fund requirements and must be redeemed by the Company in 2008. The Preferred Stock has an annual dividend rate of 11.40%, which is to be paid through the issuance of additional shares of preferred stock for the first three years and in cash thereafter. On November 1, 1996, the Company paid the first pay-in-kind dividend by issuing 84,264 shares to satisfy the dividend. Also, on January 16, 1997, the Company's Board of Directors declared the second pay-in-kind dividend which was paid on February 1, 1997 through the issuance of 30,886 additional shares to shareholders of record as of January 21, 1997.

Preferred Stock, Redemption Required

Following is a summary of the redemption of the Predecessor Company Preferred Stock and the issued and outstanding Preferred Stock, redemption required, of the Reorganized Company:

	Shares	Amount
		(In thousands)
Balance at December 31, 1993, 1994 and 1995	639,600	$ 67,266
Redemption of Predecessor Preferred Stock	(639,600)	(67,266)
Issuance of Reorganized Preferred Stock	1,000,000	100,000
Issuance of Dividend	84,264	8,426
Balance at December 31, 1996	1,084,264	$ 108,426

Optional Redemption. The Series A Preferred Stock is not redeemable at the Company's option prior to February 1, 1999; provided, however, that upon the occurrence of a change of control on or prior to February 1, 1999, the Company shall have the right to redeem the outstanding Series A Preferred Stock, in whole or in part, no earlier than 30 days nor later than 60 days from the date the change of control offer is mailed to the holders of Series A Preferred Stock, in cash, at a price per share equal to the sum of (i) 108% of the liquidation preference plus (ii) accrued and unpaid dividends (including an amount equal to a prorated dividend from the immediately preceding dividend accrual date), if any, to the redemption date. Thereafter, the outstanding Series A Preferred Stock may be redeemed, in whole or in part, at the option of the Company, in cash at the redemption prices set forth in the table below, plus all accrued and unpaid dividends (including an amount equal to a prorated dividend from the immediately preceding dividend accrual date to the date of redemption), if any, if redeemed during the twelve-month period beginning on February 1 of the years indicated below:

Year	Optional Redemption Price
1999	105.70%
2000	104.56
2001	103.42
2002	102.28
2003	101.14
2004 and thereafter	100.00

Mandatory Redemption. On February 1, 2008, the Company will be required to redeem (subject to the legal availability of funds therefor) all outstanding shares of Series A Preferred Stock at a price in cash equal to the sum of (i) the liquidation preference thereof plus (ii) all accrued and unpaid dividends, if any, to the date of redemption.

Preferred Stock, Redemption not Required

Following is a summary of the Predecessor Company Preferred Stock, redemption not required:

	Shares	Amount (In thousands)
Balance at December 31, 1993, 1994 and 1995	142,450	$ 14,198
Redemption of Predecessor Preferred Stock	(142,450)	(14,198)
Balance at December 31, 1996	–	$ –

H. Long-Term and Financing and Capital Lease Obligations

Outstanding long-term and financing and capital lease obligations are as follows:

	December 31, 1996 (In thousands)
Long-Term Obligations:	
First Mortgage Bonds (1):	
7.25% Series A, issued 1996, due 1999	$ 78,266
7.75% Series B, issued 1996, due 2001	78,771
8.25% Series C, issued 1996, due 2003	148,989
8.90% Series D, issued 1996, due 2006	235,957
9.40% Series E, issued 1996, due 2011	285,900
Pollution Control Bonds (2):	
Secured by First Mortgage Collateral Bonds:	
Variable rate bonds, due 2014	63,500
Variable rate refunding bonds, due 2013	33,300
Variable rate refunding bonds, due 2014	37,100
Variable rate refunding bonds, due 2015	59,235
Promissory note due 2007 ($227,000 due in 1997) (3)	958
Total long-term obligations	1,021,976
Financing and Capital Lease Obligations:	
Turbine lease ($1,721,000 due in 1997) (4)	5,900
Nuclear fuel ($26,385,000 due in 1997) (5)	46,630
Total financing and capital lease obligations	52,530
Total long-term and financing and capital lease obligations	1,074,506
Current maturities (Amount due within one year)	(28,333)
	$ 1,046,173

(1) First Mortgage Bonds

Substantially all of the Company's utility plant is subject to liens under the First Mortgage Indenture.

The First Mortgage Indenture imposes certain limitations on the ability of the Company to (i) declare or pay dividends on common stock; (ii) incur additional indebtedness or liens on mortgaged property; and (iii) to enter into a consolidation, merger or sale of assets.

Series A, B, C and D Bonds may not be redeemed by the Company prior to maturity. Series E Bonds may be redeemed at the option of the Company, in whole or in part, on or after February 1, 2006.

The Company is not required to make mandatory redemption or sinking fund payments with respect to the bonds prior to maturity.

During the period from February 12, 1996 through December 31, 1996, the Company repurchased approximately $46.7 million of Series A Bonds, and approximately $71.2 million of Series B Bonds.

(2) Pollution Control Bonds

The Company has four series of tax exempt Pollution Control Bonds in an aggregate principal amount of approximately $193.1 million. Each of the tax exempt issues is enhanced by a letter of credit. The Company's obligation to the issuing banks pursuant to the letter of credit reimbursement agreements are secured by First Mortgage Collateral Series Bonds (the "Collateral Series Bonds") issued pursuant to the First Mortgage Indenture in the amount of the letters of credit. The bonds bear interest at rates that are repriced weekly (4.15% to 4.25% at December 31, 1996). The bonds may be required to be repurchased at the holder's option and are subject to mandatory redemption upon the occurrence of certain events and are redeemable at the option of the Company under certain circumstances.

(3) Promissory Note

The secured note due 2007 has an annual interest rate of 5.5%.

(4) Capitalized Lease Obligation, Copper Turbine

In 1980, the Company sold and leased back a turbine and certain other related equipment from the trust-lessor for a twenty-year period, with renewal options for up to seven more years. Semiannual lease payments, including interest, which began in January 1982, were approximately $0.7 million through January 1991, and are approximately $0.9 million thereafter to July 2000. The effective annual interest rate implicit in this lease is calculated to be 9.6%.

(5) Nuclear Fuel Financing

The Company entered into a lease arrangement with a third party grantor trust, Rio Grande Resources Trust ("RGRT II"), with respect to nuclear fuel purchases for Palo Verde. The Company accounts for the lease as a capital lease and has a commitment for a three-year credit facility in the amount of $100 million, which is secured by Collateral Series Bonds, to finance nuclear fuel purchases. The credit facility provides up to $60 million for nuclear fuel purchases and up to $50 million (depending on the amount of borrowings outstanding for nuclear fuel purchases) for working capital needs and may be extended for one year at the option of the Company. Approximately $46.6 million has been drawn to finance nuclear fuel (interest rate of 8.25%) at December 31, 1996. Quarterly lease payments made are based on units of heat production.

Scheduled maturities of long-term and financing and capital lease obligations at December 31, 1996 are as follows (In thousands):

1997	$ 28,333
1998	22,050
1999	80,076
2000	954
2001	78,869

The table above does not reflect future nuclear fuel purchases and related obligations and maturities.

I. Federal Income Taxes

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 1996 and December 31, 1995, are presented below (In thousands):

	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Deferred tax assets:		
Letters of credit draws	$ –	$ 100,946
Gain on sale and leaseback transactions	–	46,410
Accrued lease expense, net of interim payments (Note B)	–	85,942
Reorganization expenses financed with bonds	22,526	–
Accumulated deferred investment tax credits	–	27,396
Capital leases	2,873	25,100
Benefits of tax loss carryforwards	256,510	3,582
Investment tax credit carryforward	20,410	11,984
Alternative minimum tax credit carryforward	9,627	35,964
Other	92,643	100,900
Total gross deferred tax assets	404,589	438,224
Less valuation allowance:		
Federal	12,661	217,509
State	17,941	39,808
Total valuation allowance	30,602	257,317
Net deferred tax assets	373,987	180,907
Deferred tax liabilities:		
Plant, principally due to differences in depreciation and basis differences	(288,416)	(235,181)
Other	(11,687)	(15,736)
Total gross deferred tax liabilities	(300,103)	(250,917)
Net accumulated deferred income taxes	$ 73,884	$ (70,010)

Upon adoption of SFAS No. 109, a valuation allowance was recorded for deferred tax assets which may not be realized, including tax carryforwards that the Company may not utilize before their expiration. The valuation allowance decreased by approximately $226.7 million in 1996, $4.5 million in 1995 and $4.4 million in 1994. The decrease in 1996 was primarily due to the Company's belief that, because of the Rate Stipulation, Reorganization, and other factors, it is more likely than not that the Company will have sufficient taxable income in the future to utilize most of the tax net operating loss ("NOL") carryforward benefits. Prior to the effective date of the Reorganization, the Predecessor Company did not assume future taxable income for the utilization of NOL carryforwards. Approximately $27.1 million of the Company's valuation allowance at December 31, 1996, if subsequently recognized as a tax benefit, would be credited directly to capital in excess of stated value in accordance with SOP 90-7.

As discussed in Note D, the Company's income tax provision has been calculated under SFAS No. 109. The Company recognized income taxes as follows (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Income tax expense (benefit):				
Federal:				
Current	$ (17,203)	$ –	$ 13,757	$ 6,320
Deferred	38,828	(2,340)	(21,703)	(21,200)
Investment tax credit amortization	–	(325)	(2,828)	(2,838)
Subtotal current operations	21,625	(2,665)	(10,774)	(17,718)
Adjustment of assets and liabilities to fair value (elimination of accumulated deferred investment tax credits)	–	(77,950)	–	–
Deferred included in reorganization items	–	(172,899)	(1,194)	(1,824)
Income tax expense on interest income during bankruptcy	–	583	4,633	2,720
Total	$ 21,625	$ (252,931)	$ (7,335)	$ (16,822)
State:				
Current	$ 278	$ 116	$ 935	$ 584
Deferred	4,767	(866)	(5,959)	(364)
Subtotal current operations	5,045	(750)	(5,024)	220
Deferred included in reorganization items	–	(17,494)	–	–
Total	$ 5,045	$ (18,244)	$ (5,024)	$ 220

The current federal income tax benefit for 1996 results primarily from the carryback of 1996 alternative minimum tax ("AMT") NOL to the 1993, 1994 and 1995 tax years and decreased by an expense for the reduction of investment tax credits ("ITC") utilized. Deferred federal income tax includes an offsetting AMT deferred expense of approximately $24.0 million and a benefit for an increase in ITC carryforward of approximately $6.8 million.

The current federal income tax expense for 1995 and 1994 results primarily from the accrual of AMT expense. The deferred federal income tax benefit recorded in 1995 and 1994 includes offsetting AMT credits of approximately $18.3 million and $8.4 million, respectively. For the years 1995 and 1994, ITC utilized of approximately $4.6 million and $2.1 million, respectively, was recorded as a reduction to current tax and included as a deferred tax expense.

Federal income tax provisions differ from amounts computed by applying the statutory rate of 35% to the book loss before federal income tax as follows (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	Years Ended December 31, 1994
Federal income tax expense (benefit) computed on income (loss) at statutory rate	$ 22,240	$ 45,339	$ (14,229)	$ (15,741)
Difference due to:				
ITC amortization (net of deferred taxes)	–	(211)	(1,838)	(1,845)
Nondeductible bankruptcy costs	–	3,604	5,925	3,915
Federal valuation allowance	–	(204,848)	(4,461)	(1,927)
Adjustment of assets and liabilities to fair value (elimination of accumulated deferred ITCs)	–	(77,950)	–	–
Reorganization costs (including the nontaxable extraordinary gain on the discharge of debt)	–	(27,745)	–	–
Other	(615)	8,880	7,268	(1,224)
Total federal income tax expense (benefit)	$ 21,625	$ (252,931)	$ (7,335)	$ (16,822)
Effective federal income tax rate	34.0 %	(195.3)%	18.0 %	37.4 %

The Company had approximately $733.0 million of tax NOL carryforwards, approximately $20.4 million of ITC carryforwards and approximately $9.6 million of AMT credit carryforwards as of December 31, 1996. If unused, the NOL carryforwards would expire at the end of the years 2006 through 2011, the ITC carryforwards would expire in the years 2001 through 2005 and the AMT credit carryforwards have an unlimited life.

The Reorganization and the associated implementation of fresh-start reporting gave rise to significant items of income and expense for financial reporting purposes that are not included in taxable income. These reorganization items resulted in an effective tax rate for the period from January 1 to February 11, 1996 that is significantly different than the current U.S. statutory rate of 35%.

The Bankruptcy Court entered an order on May 10, 1994 approving the terms of a settlement with the Internal Revenue Service ("IRS") covering tax periods prior to 1992, pursuant to which the Company paid approximately $6.2 million, which primarily represents interest.

J. Commitments and Contingencies

Sale/Leaseback Indemnification Obligations

Pursuant to the participation agreements and leases entered into in the sale/leaseback transactions, if the lessors incur additional tax liability or other loss as a result of federal or state tax assessments related to the sale/leaseback transactions, the lessors may have claims against the Company for indemnification. Pursuant to settlement agreements entered into between the Company and the lessors under the Palo Verde Leases, certain of the Company's indeminity obligations related to tax matters have continued after the Effective Date.

One of the lessors in the sale/leaseback transactions related to Unit 2 of Palo Verde has notified the Company that the IRS has raised issues, primarily related to ITC claims by the lessor, regarding the income tax treatment of the sale/leaseback transactions. The Company estimates that the total amount of potential claims for indemnification from all lessors related to the issues raised by the IRS could approximate $10.0 million, exclusive of any applicable interest, if the IRS prevails. This matter is at a preliminary stage and, although the Company believes the lessor has meritorious defenses to the IRS' position, the Company cannot predict the outcome of the matter or the Company's liability for any resulting claim for indemnification. The Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to this matter.

Environmental Matters

The Company is subject to regulation with respect to air, soil and water quality, solid waste disposal and other environmental matters by federal, state and local authorities. These authorities govern current facility operations and exercise continuing jurisdiction over facility modifications. Environmental regulations can change rapidly and are difficult to predict. Because construction of new facilities is subject to standards imposed by environmental regulation, substantial expenditures may be required to comply with such regulations. The Company analyzes the costs of its obligations arising from environmental matters on an ongoing basis, and management believes it has made adequate provision in its financial statements to meet such obligations. However, unforseen expenses associated with compliance could have a material, adverse effect on the future operations and financial condition of the Company.

PCB Treatment, Inc. The Company received a request from the U.S. Environmental Protection Agency ("EPA") to participate in the remediation of polychlorinated biphenyls ("PCBs") at two facilities in Kansas City, Missouri, which had been operated by PCB Treatment, Inc. ("PTI"). The Company's manifests indicate that between 1982 and 1986, the Company sent 23 shipments of PCBs or PCB-containing electric equipment ("PCB Equipment") to PTI, accounting for approximately 2 to 3%, by weight, of the PCBs and PCB Equipment received at that site by PTI. Presently, PTI has discontinued operations and the EPA has determined that PTI's abandoned facilities require remediation.

The Company and the PTI Steering Committee, which consists of the largest generators of the PCBs sent to PTI, have executed a settlement agreement. In consideration for the payment of approximately

$0.2 million, the settlement agreement excuses any further liability to the Steering Committee by the Company and indemnifies the Company for any liabilities to other parties as may be asserted in the future.

The Company may still face liability for possible deliveries of PCBs by PTI to a third site which is also subject to remedial action by the federal authorities, except to the extent that those PCBs were transferred from the first site. The Company's records do not indicate any deliveries of PCBs to this third site. Management believes the Company is unlikely to face substantial unindemnified liabilities associated with this third site.

Coal Mine Reclamation. The Company has been informed by APS that the Company's estimated financial obligation for coal mine reclamation at Four Corners is not being fully reflected in the costs for which the Company is billed. APS, the operating agent of Four Corners, is performing an analysis to establish an appropriate revised cost estimate. Based on preliminary estimates from APS and the coal provider, the Predecessor Company recorded a liability of approximately $12 million which reflects the present value of the estimated future costs of reclamation at the Effective Date to reflect its share of the coal mine reclamation obligation.

K. Litigation

Litigation with Central and South West Corporation

In May 1993, the Company entered into the Merger Agreement, pursuant to which the Company would have been acquired by CSW. In June 1995, CSW terminated the Merger Agreement. In response, the Company filed a complaint against CSW in the 205th Judicial District Court of El Paso County, Texas, alleging, among other claims, breach of contract, breach of duty of good faith and fair dealing, breach of fiduciary duty, business disparagement, tortious interference with contract and fraud in the inducement. The Company sought an unspecified amount of damages, punitive damages, attorneys' fees and costs. In June 1995, CSW filed an adversary proceeding against the Company in the Bankruptcy Court seeking the recovery of termination fees of $25 million, approximately $3.7 million in attorneys' fees and expenses that CSW claims it advanced on behalf of the Company in certain regulatory proceedings, and $25 million for the alleged violation of the Merger Agreement's no-solicitation provisions. All of the claims by both parties were tried in the Bankruptcy Court. The trial concluded on January 30, 1997, and the matter has been taken under advisement by the presiding judge. A ruling is expected in March 1997. The Company cannot predict the outcome of this litigation, but does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to the litigation between the Company and CSW. Pursuant to the terms of the Reorganization, the first $20 million in proceeds, if any, to the Company from this litigation will be distributed to the holders of preferred stock and common stock of the Predecessor Company.

Litigation with Las Cruces

Las Cruces is attempting to replace the Company as its electric service provider by acquiring, through condemnation or otherwise, the distribution assets and other facilities used to provide electric service to customers in Las Cruces. Sales to customers in Las Cruces represented approximately 7% of the

Company's operating revenues in 1996. Las Cruces has two actions pending against the Company in federal district court in New Mexico, one seeking to recover franchise fees despite the expiration of the Company's Las Cruces franchise in March 1994 and one seeking a declaratory judgment that Las Cruces can proceed with a condemnation action against the Company. In addition, the New Mexico State Legislature has recently passed a bill that would allow Las Cruces to proceed with the condemnation.

In the franchise fee action, Las Cruces is seeking the reasonable value of the Company's use, occupation and rental of Las Cruces' rights-of-way or damages for trespass and an unspecified amount of punitive damages. The Company has filed an answer denying that it has any liability or continuing payment obligation to Las Cruces regarding franchise fees or use of the Las Cruces rights-of-way, and also denies that it has committed any trespass. The Company intends to vigorously defend the lawsuit. The Company has also filed a counterclaim seeking to condemn, pursuant to statutory authority, those Las Cruces rights-of-way currently used and occupied by the Company. Las Cruces has filed an answer contesting the Company's right to proceed with such a condemnation. In August 1996, the court severed the Company's counterclaim from Las Cruces' claims for all purposes, and stayed all proceedings on the Company's counterclaim until further order of the court. The trial of Las Cruces' claims is set for May 1997. The Company has reserved in its financial statements an amount equal to the franchise fees under the expired agreement.

In April 1995, Las Cruces filed a Complaint for Declaratory Judgment against the Company in the District Court for Dona Ana County, New Mexico, seeking a declaratory judgment that Las Cruces has a right of eminent domain to condemn the electric distribution system and related facilities owned and operated by the Company within and adjacent to the city limits that provide or assist in the provision of electricity within the municipal boundaries of Las Cruces. In May 1995, the Company removed the case to the United States District Court for the District of New Mexico. In October 1995, the Company's motion for summary judgment was denied and the Court ruled that although Las Cruces lacks express statutory authority to condemn the Company's assets, such express authority is required only if the proposed condemnation would materially impair, obliterate or destroy the existing use. Following a trial on the merits, the federal magistrate issued an opinion holding that Las Cruces had not met its burden of proof that its plan would not materially impair the public use of the Company's property sought to be condemned. The magistrate also granted the Company's motion to certify to the New Mexico Supreme Court the question as to whether Las Cruces possesses the authority to condemn the Company's property for use as a municipal utility when that property is already devoted to public use. In February 1997, the New Mexico Supreme Court heard oral arguments and is expected to issue its ruling in the near future.

In March 1997, the New Mexico House of Representatives and Senate passed a bill that would give Las Cruces the authority to acquire and operate the Company's distribution system within both the city limits and a territory within five miles of the municipal boundary. If the Governor signs the bill, it would become law immediately and most likely make the issues presented to the New Mexico Supreme Court moot.

Las Cruces has taken several actions to position itself to acquire portions of the Company's distribution system and certain related facilities in the event it can proceed with condemnation. See Note C for discussion regarding Las Cruces' filing with the FERC for determination of stranded cost. In June 1994, the Las Cruces City Council approved a resolution selecting SPS to provide operation and maintenance services for the proposed Las Cruces electric distribution system, substations and associated transmission facilities and authorizing the staff of Las Cruces to negotiate a contract with SPS related to such services. In August 1994, SPS and Las Cruces entered into a fifteen-year contract granting SPS the right to provide all of the electric power and energy required by Las Cruces during the term of the contract. In addition, Las Cruces announced that, in October 1995, it sold approximately $73 million in revenue bonds to provide funding to finance the acquisition by condemnation or negotiated purchase of the Company's electrical distribution assets within and adjacent to the Las Cruces city limits.

The Company has filed a lawsuit in the Dona Ana County District Court and is pursuing a complaint simultaneously before the New Mexico Commission challenging the legality of the sale of the revenue bonds, and the New Mexico Commission is investigating the agreement between SPS and Las Cruces which would grant, in certain circumstances, Las Cruces an option to sell electric utility assets acquired through condemnation to SPS. In August 1996, the Dona Ana County District Court issued an opinion letter stating that Section 3-23-3 of the New Mexico Municipal Code is inapplicable to home rule municipalities and Las Cruces, therefore, was not required to acquire the New Mexico Commission's approval before issuing revenue bonds to acquire utility property. However, the Court did agree with the Company that the revenue bonds, in this case backed by utility revenues, are subject to the same requirements of other revenue bonds backed by gross receipts tax revenues. Therefore, if the Court's finding of the applicability of Las Cruces' home rule authority is overturned on appeal, the Company's position that the issuance of the bonds required prior approval could be upheld. The Court's order was signed and entered in November 1996. The Company has filed an appeal with the New Mexico Court of Appeals.

The Company continues to believe that it can provide lower cost electric service to customers in Las Cruces than can be achieved through a municipal takeover. Accordingly, the Company has stated its strong preference for a resolution of its differences with Las Cruces through negotiation rather than litigation and condemnation. The Company intends to vigorously pursue before the FERC its right to recover stranded costs from Las Cruces in the event Las Cruces succeeds in leaving the system.

If Las Cruces succeeds in its efforts to condemn the Company's distribution system, the Company could lose its Las Cruces customer base, although the Company would receive "just compensation" as established by the court under New Mexico law. "Just compensation" is generally defined as the amount of money that would compensate the party whose property is condemned. In the Company's case, this amount would be the difference between the value of the Company's entire system prior to the taking, as compared to the value of the entire system after the taking. The Company is unable to predict the outcome of Las Cruces' litigation or its efforts to replace the Company as its electric service provider or the effects it may have on the Company's financial position, results of operations and cash flows. The Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements related to these matters.

Transmission Service to Mexico

In September 1996, Enron, a wholesale power marketer and one of the companies that submitted a bid to the CFE in connection with renewal of the interchange agreement for the supply of power to Ciudad Juarez, Mexico, filed a complaint against the Company with the FERC. Enron's complaint sought emergency relief and requested the FERC to direct the Company to enter into an agreement with Enron to provide Enron with firm point-to-point transmission service to the CFE under its open access transmission tariff.

In October 1996, the FERC issued an order requiring the Company to provide Enron with firm point-to-point transmission service over the Company's transmission system to substation facilities near the border. The FERC, however, concurred with the Company's position that the FERC does not have jurisdiction to order transmission across the border, suggesting that the DOE has such jurisdiction. Pursuant to an emergency application filed by Enron with the DOE, on October 30, 1996, the DOE issued a Notice of Delegation and Assignment which delegated to the FERC its authority to carry out the DOE's duties in this case. In its response to the DOE's delegation of authority, the Company has asserted that the DOE has no authority to require transmission access for delivery of power to the CFE. However, the Company agreed to provide access, to the extent transmission capacity is available, to a winning bidder in 1997, if the winning bidder is someone other than the Company, pending resolution of this jurisdictional dispute. The Company's agreement to provide such access in no way prejudices the Company's position that, under current law, access is not required. The FERC has docketed the Delegation and Assignment and the process is expected to continue throughout 1997.

Water Cases

San Juan River System. The Four Corners Participants are among the defendants in a suit filed by the State of New Mexico in 1975 in state district court in New Mexico against the United States of America, the City of Farmington, New Mexico, the Secretary of the Interior as Trustee for the Navajo Nation and other Indian tribes and certain other defendants (*State of New Mexico ex rel. S. E. Reynolds, New Mexico State Engineer v. United States of America, et al.*, Eleventh Judicial District Court, County of San Juan, State of New Mexico, Cause No. 75-184). The suit seeks adjudication of the water rights of the San Juan River Stream System in New Mexico, which, among other things, supplies the water used at Four Corners. The case has been inactive for many years. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Gila River System. In connection with the construction and operation of Palo Verde, APS entered into contracts with certain municipalities granting APS the right to purchase effluent for cooling purposes at Palo Verde. In 1986, a summons was served on APS that required all water claimants in the Lower Gila River Watershed in Arizona to assert any claims to water in an action pending in Maricopa County Superior Court, titled *In re The General Adjudication of All Rights to Use Water in the Gila River System and Source.* Palo Verde is located within the geographic area subject to the summons and the rights of the Palo Verde Participants to the use of groundwater and effluent at Palo Verde is potentially at issue in the action. APS, as operating agent, filed claims that dispute the court's jurisdiction over the Palo Verde Participants' groundwater rights and their contractual rights to effluent relating to Palo Verde and, alternatively, seek confirmation of such rights. In December 1992, the Arizona Supreme Court heard oral argument on certain issues in this matter that are pending on interlocutory appeal. Issues important to Palo Verde Participants' claims were remanded to the trial court for further action and the trial court certified its decision for interlocutory appeal to the Arizona Supreme Court. In September 1994, the Arizona Supreme Court granted review of the June

1994 trial court decision. No trial date has been set in the matter. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Four Corners

In July 1995, the Navajo Nation enacted the Navajo Nation Air Pollution Prevention and Control Act, the Navajo Nation Safe Drinking Water Act and the Navajo Nation Pesticide Act (collectively, the "Acts"). In October 1995, the Four Corners Participants requested that the United States Secretary of the Interior resolve their dispute with the Navajo Nation regarding whether the Acts apply to operation of Four Corners. The Four Corners Participants subsequently filed a lawsuit in the District Court of the Navajo Nation, Window Rock District, seeking, among other things, a declaratory judgment that (i) the Four Corners leases and federal easements preclude the application of the Acts to the operation of Four Corners; and (ii) the Navajo Nation and its agencies and courts lack adjudicatory jurisdiction to determine the enforceability of the Acts as applied to Four Corners. On October 18, 1995, the Navajo Nation and the Four Corners Participants agreed to indefinitely stay the proceedings referenced above so that the parties may attempt to resolve the dispute without litigation. Although the outcome of this case and the possible effects on the Company cannot be determined at this time, the Company does not believe it is probable that a loss has been incurred and, therefore, has made no provision in the accompanying financial statements for this matter.

Other Legal Proceedings

The Company is a party to various other claims, legal actions and complaints. In many of these matters the Company has excess casualty liability insurance which is applicable. Based upon a review of these claims and applicable insurance coverage, management is of the opinion that none of these claims will have a material adverse effect on the operations or financial position of the Company. However, these actions and claims in the aggregate seek substantial damages against the Company and are subject to the uncertainties inherent in any litigation. The Company is defending itself vigorously in all these matters.

L. Benefit Plans

Pension Plan

The Company's Retirement Income Plan (the "Retirement Plan") covers employees who have completed one year of service with the Company, are 21 years of age and work at least a minimum number of hours each year. The Retirement Plan is a qualified noncontributory defined benefit plan. Upon retirement or death of a vested plan participant, assets of the Retirement Plan are used to pay benefit obligations under the Retirement Plan. Contributions from the Company are based on the minimum funding amounts required by the Department of Labor ("DOL") and IRS under provisions of the Retirement Plan, as actuarially calculated. The assets of the Retirement Plan are invested in equity securities, fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

EL PASO ELECTRIC COMPANY

NOTES TO FINANCIAL STATEMENTS

The Company's Supplemental Retirement and Survivor Income Plan for Key Employees (the "SERP") is a non-qualified, non-funded defined benefit plan which covers certain former employees of the Company. The pension cost for the SERP is based on substantially the same actuarial methods and economic assumptions as those used for the Retirement Plan. As part of the Reorganization, the Company terminated the SERP with respect to all active employees resulting in a curtailment gain of approximately $2.0 million. In conjunction therewith, the Company entered into retirement agreements with ten officers who had been participants in the SERP resulting in an increase in the accumulated benefit obligation of approximately $10.2 million. This increase in the accumulated benefit obligation and the curtailment gain were recognized as reorganization items by the Predecessor Company.

Net periodic pension cost for the Retirement Plan and the SERP under SFAS No. 87, "Employers' Accounting for Pensions," is made up of the components listed below as determined using the projected unit credit actuarial cost method (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December 31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Service costs for benefits earned during the period	$ 2,148	$ 354	$ 2,011	$ 2,453
Interest costs on projected benefit obligation	5,774	749	5,157	4,896
Actual return on plan assets	(5,019)	(570)	(9,267)	378
Net amortization and deferral	842	113	6,008	(3,383)
Recognition of previously unrecognized items	–	21,738	–	–
Net periodic pension cost recognized	$ 3,745	$ 22,384	$ 3,909	$ 4,344

The assumed annual discount rates used in determining the net periodic pension cost were 7.25%, 8.50% and 7.25% for 1996, 1995 and 1994, respectively.

The pension cost includes amortization of unrecognized items. In the application of fresh-start reporting, the Company recorded the then existing unrecognized items as of February 11, 1996 in the amount of approximately $21.7 million.

The funded status of the plans and amount recognized in the Company's balance sheets at December 31, 1996 and 1995 are presented below (In thousands):

	Reorganized Company December 31, 1996		Predecessor Company December 31, 1995	
	Retirement Income Plan	SERP	Retirement Income Plan	SERP
Actuarial present value of benefit obligations:				
Vested benefit obligation	$ (57,366)	$ (18,171)	$ (55,591)	$ (9,559)
Accumulated benefit obligation	$ (59,883)	$ (18,171)	$ (57,844)	$ (11,570)
Projected benefit obligation	$ (72,951)	$ (18,171)	$ (70,958)	$ (13,441)
Plan assets at fair value	61,460	–	53,512	–
Projected benefit obligation in excess of plan assets	(11,491)	(18,171)	(17,446)	(13,441)
Unrecognized net (gain) loss from past experience	(3,520)	(1,368)	11,562	2,648
Unrecognized prior service cost	–	–	212	(407)
Unrecognized transition obligation	–	–	2,449	260
Accrued pension liability	$ (15,011)	$ (19,539)	$ (3,223)	$ (10,940)

Actuarial assumptions used in determining the actuarial present value of projected benefit obligations are as follows:

	1996	1995
Discount rate	7.50%	7.25%
Rate of increase in compensation levels	5.00%	5.00%
Expected long-term rate of return on plan assets	8.50%	8.50%

Other Postretirement Benefits

The Company provides certain health care benefits for retired employees and their eligible dependents and life insurance benefits for retired employees only. Substantially all of the Company's employees may become eligible for those benefits if they reach retirement age while working for the Company. Those benefits are accounted for under SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." Contributions from the Company are based on the funding amounts required by the Texas Commission in the Rate Stipulation. The assets of the Other Postretirement Benefits Plan are invested in fixed income instruments and cash equivalents and are managed by professional investment managers appointed by the Company.

The benefit cost includes amortization of unrecognized items. In the application of fresh-start reporting, the Company recorded the then existing unrecognized items as of February 11, 1996 in the amount of approximately $52.3 million.

Net periodic postretirement benefit cost is made up of the components listed below (In thousands):

	Reorganized Company	Predecessor Company		
	Period From February 12 to December31, 1996	Period From January 1 to February 11, 1996	Years Ended December 31, 1995	1994
Service costs for benefits earned during the period	$ 2,209	$ 279	$ 1,603	$ 2,064
Interest costs on accumulated postretirement benefit obligation	4,723	607	4,046	3,909
Actual return on plan assets	(146)	–	–	–
Amortization of transition obligations	–	263	2,363	2,172
Amortization of (gain) loss	–	60	(54)	103
Recognition of previously unrecognized items	–	52,340	–	–
Net periodic postretirement benefit cost recognized	$ 6,786	$ 53,549	$ 7,958	$ 8,248

The funded status of the plan and amount recognized in the Company's balance sheet at December 31, 1996 and 1995 are presented below (In thousands):

	Reorganized Company December 31, 1996	Predecessor Company December 31, 1995
Actuarial present value of postretirement benefit obligation:		
Accumulated postretirement benefit obligation:		
Retirees	$ (29,908)	$ (32,656)
Active participants	(47,691)	(40,831)
	(77,599)	(73,487)
Plan assets at fair value	8,050	–
Accumulated postretirement benefit obligation in excess of plan assets	(69,549)	(73,487)
Unrecognized net (gain) loss from past experience	(1,764)	15,182
Unrecognized transition obligation	–	38,007
Accrued postretirement benefit liability	$ (71,313)	$ (20,298)

For measurement purposes, a 10.9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 1997; the rate was assumed to decrease gradually to 6% for 2004 and remain at that level thereafter. The health care cost trend rate assumption has a significant effect on the amounts reported. To illustrate, increasing the assumed health care cost trend rates by one percentage point in each year would increase the accumulated postretirement benefit obligation as of December 31, 1996 by $9.4 million and the aggregate of the service and interest cost components of net periodic postretirement benefit cost for the year ended December 31, 1996 by $1.3 million.

Actuarial assumptions used in determining the actuarial present value of accumulated postretirement benefit obligation are as follows:

	1996	1995
Discount rate	7.50%	7.25%
Rate of increase in compensation levels	5.00%	5.00%

M. Franchises and Significant Customers

City of El Paso Franchise

The Company's major franchise is with the City of El Paso, Texas. The franchise agreement provides an arrangement for the Company's utilization of public rights of way necessary to serve its retail customers within the City of El Paso. Under the Stipulation, the new franchise with the City of El Paso extends through August 1, 2005.

Las Cruces Franchise

The Company's franchise with Las Cruces expired in March 1994. The Company has continued to provide electric service to customers within Las Cruces and expects and intends to continue to do so. See Note K.

Military Installations

The Company currently serves Holloman Air Force Base ("Holloman"), White Sands Missile Range ("White Sands") and the United States Army Air Defense Center at Fort Bliss ("Ft. Bliss"). The Company's sales to the military bases represented approximately $20.0 million or 3% of operating revenues in 1996. The Company signed a new contract with Ft. Bliss in August 1996, which provides that Ft. Bliss will take service from the Company through 1999, with the right thereafter to continue service on a year to year basis for two years. The Company has a contract for service to Holloman for a ten year term beginning on December 27, 1995. In August 1996, the Army advised the Company that White Sands would continue to purchase retail electric service from the Company pursuant to the retail service contract which was set to expire on December 31, 1993, but which had previously been unilaterally extended by the Army for an indefinite period, until written termination of such contract by the Army not less than one year in advance of the termination date.

Significant Customers

In 1996, 1995 and 1994, IID, a wholesale customer, accounted for approximately $41.6 million, $43.3 million and $51.1 million or 7.2%, 8.6% and 9.5%, respectively, of operating revenues. During 1996, 1995 and 1994, the Company recorded revenues pursuant to its contract with the CFE in the amount of approximately $43.9 million, $39.4 million and $42.7 million, respectively. Under the new agreement with the CFE, revenues in 1997 related to power sales to the CFE are expected to be lower than revenues recorded in 1996. See Note C.

N. Financial Instruments

SFAS No. 107, "Disclosure about Fair Value of Financial Instruments", requires the Company to disclose estimated fair values for its financial instruments. The Company has determined that cash and temporary investments, accounts receivable, long-term contract receivable, accounts payable, customer deposits, decommissioning trust funds, long-term debt, and preferred stock meet the definition of financial instruments. The carrying amounts of cash and temporary investments, accounts receivable, accounts payable, and customer deposits approximate fair value because of the short maturity of these items. Based on prevailing interest rates, the fair value of the long-term contract receivable approximates its carrying value. Decommissioning trust funds are carried at market value.

The fair values of the Company's long-term debt, including the current portion thereof, and preferred stock, are based on estimated market prices for similar issues and are presented in the table below:

	Carrying Amount	Estimated Fair Value
	(In thousands)	
First Mortgage Bonds	$ 827,883	$ 864,047
Pollution Control Bonds	193,135	193,135 (2)
Nuclear Fuel Financing (1)	46,630	46,630 (3)
Capitalized Lease Obligations, Copper Turbine and Other (1)	6,858	6,858 (4)
Total	$ 1,074,506	$ 1,110,670
Preferred Stock	$ 108,426	$ 119,377

(1) Includes current maturities.
(2) The interest rate on the Company's pollution control bonds is reset weekly to reflect current market rates. Consequently, the carrying value approximates fair value.
(3) The interest rate on the Company's financing and capital lease obligations for nuclear fuel purchases is reset every quarter to reflect current market rates. Consequently, the carrying value approximates fair value.
(4) Based on prevailing interest rates the estimated fair value of the Copper Turbine lease and other approximate their carrying value.

O. Selected Quarterly Financial Data (Unaudited)

	Predecessor Company	Reorganized Company				Predecessor Company			
	Period From January 1 to February 11, 1996	Period From February 12 to March 31, 1996	1996 Quarters 2nd	3rd	4th	1995 Quarters 1st	2nd	3rd	4th
		(In thousands except for share data)							
Operating revenues	$ 54,949	$ 69,907	$144,388	$166,656	$143,023	$112,389	$124,683	$148,177	$119,368
Operating income	5,089	14,748	34,096	44,363	27,580	11,950	17,851	31,175	5,170
Income (loss) before reorganization items (expense) and extraordinary gain on discharge of debt	(4,053)	1,689	9,500	22,770	7,960	(14,449)	(7,130)	12,258	(14,020)
Reorganization items (expense), net of income tax benefit (expense)	122,251	–	–	–	–	(1,999)	(2,472)	(658)	(4,849)
Extraordinary gain on discharge of debt	264,273 (1)	–	–	–	–	–	–	–	–
Net income (loss) applicable to common stock	382,471	137	6,603	19,793	4,898	(16,448)	(9,602)	11,600	(18,869)
Net income (loss) per common share:									
Income (loss) before extraordinary gain on discharge of debt	3.33	0.00	0.11	0.33	0.08	(0.46)	(0.27)	0.33	(0.54)
Extraordinary gain on discharge of debt	7.43 (1)	–	–	–	–	–	–	–	–
Net income (loss)	10.76	0.00	0.11	0.33	0.08	(0.46)	(0.27)	0.33	(0.54)

(1) Reflects the discharge of obligations subject to compromise for less than their recorded amounts.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

PART III and PART IV

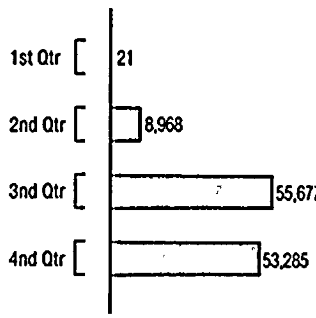
The information set forth in Part III and Part IV has been omitted from this Annual Report to Shareholders.

Year In Review

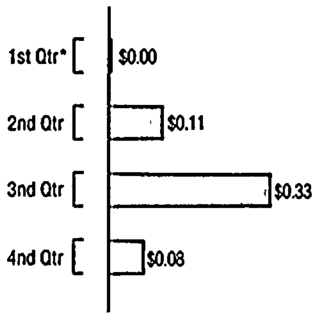
Financial Performance

After emerging from bankruptcy protection on February 12, 1996, the Company achieved positive performance through each quarter of 1996. The Company continued to experience above average sales growth over 1995 levels: 4.4% for retail sales and 6.5% for sales for resale. Strong internally generated cash flow was further enhanced by two non-operating events, the sale of a warrant and the reduction of professional fees related to the Company's bankruptcy proceeding. This strong cash flow allowed El Paso Electric to aggressively reduce outstanding debt levels by $118 million in 1996 with first mortgage bond repurchases on the open market. Working toward its deleveraging objectives, the Company has repurchased an additional $50 million through March 31, 1997.

First Mortgage Bonds Repurchased
(dollars in thousands)

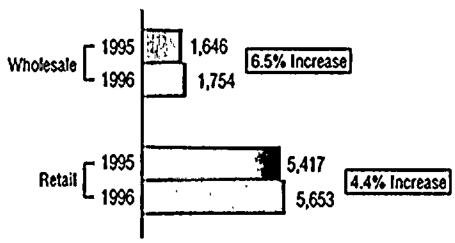


Earnings Per Share
(in dollars)

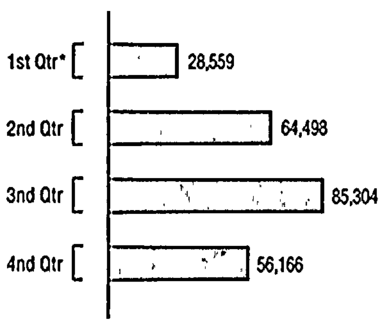


* For period Feb 12 thru Mar 31

Comparative Energy Sales
(in GWh)



EBITDA
(dollars in thousands)



* For period Feb 12 thru Mar 31

Highlights

Financial Results
(dollars in thousands except per share amounts)

Total operating revenues*	$523,974
Net income available to common*	$31,431
Weighted average shares outstanding (12/31/96)*	60,181,494
Actual shares outstanding (12/31/96)	60,179,981
Book value per share	$5.50
Market price per share (year-end closing)	$6.50

Operating Data

Megawatt-hour sales	
Retail	5,652,907
Sales for resale	1,753,553
Owned generating capacity (MW)	1,500
Total system peak demand (MW)	1,387
Number of customers	279,326

*For period February 12 thru December 31, 1996

Since the Company emerged from bankruptcy protection mid-first quarter, the financial statements for 1996 are divided between the Predecessor and Reorganized Company. The financial performance associated with the first 42 days, through February 11, belong to the Predecessor Company, while the performance from February 12 through the end of the year belong to the Reorganized Company. In order to provide 12 month comparative information for the Reorganized Company, the first 42 days of 1996 have been calculated to reflect the effects of Reorganization as if it had occurred on January 1.

Pro Forma Condensed Statements of Operations For The Period From January 1 To February 11, 1996 And Twelve Months Ended December 31, 1996 (Unaudited, In Thousands)

	Period From January 1 to February 11, 1996	Pro Forma Adjustments		Period From January 1 to February 11, 1996	Period from February 12 to December 31, 1996	Twelve Months Ended December 31, 1996
	Historical	Debit	Credit	Pro Forma	Historical	Pro Forma
Operating revenues	$ 54,949	$	$ 4,470 (1)	$ 59,419	$ 523,974	$ 583,393
Operating expenses:						
Fuel	10,125			10,125	92,899	103,024
Purchased and interchanged power	2,282			2,282	17,821	20,103
Other operations	23,559		8,717 (2) 309 (3)	14,533	115,742	130,275
Maintenance	4,743			4,743	34,702	39,445
Taxes other than FIT and SIT	6,024			6,024	38,547	44,571
Other income (deductions):						
Investment income			568 (3)	568	4,796	5,364
Other, net	50			50	(681)	(631)
EBITDA	8,266		14,064	22,330	228,378	250,708
Depreciation and amortization	6,577	3,618 (5)		10,195	79,772	89,967
Interest charges (credits):						
Interest on long-term debt	9,569	11,367 (6)	9,569 (7)	11,367	85,633	97,000
Other interest		746 (6)		746	5,722	6,468
Interest capitalized and deferred	(412)			(412)	(5,189)	(5,601)
Net interest expense	9,157	12,113	9,569	11,701	86,166	97,867
Income tax (benefit) expense	(3,415)	3,059 (8)		(356)	26,670	26,314
Non-recurring items:						
Gain on the sale of investment					3,844	3,844
Settlement of bankruptcy professional fees					2,305	2,305
					6,149	6,149
Income (loss) before reorganization items, net of tax benefit and extraordinary item	(4,053)	18,790	23,633	790	41,919	42,709
Reorganization items, net of tax benefit	122,251	122,251 (9)				
Income before extraordinary item	118,198	141,041	23,633	790	41,919	42,709
Extraordinary item	264,273	264,273 (9)				
Net income	382,471	405,314	23,633	790	41,919	42,709
Preferred stock dividend requirements		1,464 (10)		1,464	10,488	11,952
Net income (loss) applicable to common stock	$ 382,471	$ 406,778	$ 23,633	$ (674)	$ 31,431	$ 30,757

El Paso Electric Company Footnotes to Proforma Condensed Statements of Operations For The Period From January 1, 1996 to February 11, 1996

(1) To record the effects of the Rate Stipulation, assuming that rates specified in the Rate Stipulation were implemented as of January 1, 1996.

(2) To eliminate the lease expense associated with the reaquired Palo Verde leases.

(3) To reflect the elimination of the amortization of the unrecognized items as of January 1, 1996 for benefit plans, which unrecognized items were recorded in accordance with fresh-start reporting.

(4) To reduce interest earned on accumulated cash resulting from the Bankruptcy Case included in Reorganization items in the historical financial statements to an amount reflecting interest income on a reduced cash and temporary investments balance.

(5) To adjust depreciation and amortization to reflect the pro forma utility plant amounts.

(6) To reflect estimated interest charges on new debt, the amortization of the related debt issuance costs and accrual of interest costs on the liability for estimated future expenditures to decommission Palo Verde.

(7) To eliminate historical interest expense related to obligations that existed prior to the Reorganization.

(8) To adjust income tax expense to reflect the expense calculated on pro forma pre-tax income at the statutory federal tax rate of 35% and the applicable statutory state tax rates.

(9) To eliminate amounts resulting from the emergence from bankruptcy.

(10) To record the Preferred Stock dividend requirements at an annual rate of 11.40%, compounded for the payment of dividends in additional shares of Preferred Stock.

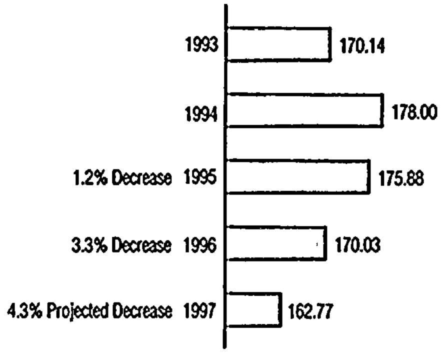
Historical
Trends

Improving Operating Fundamentals

Historically strong growth and increasing efficiency provide a basis for continued improvement in fundamentals.

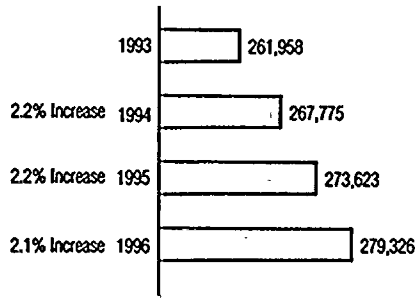
Operations & Maintenance Expense *
1993 - 1997

(in millions of dollars)

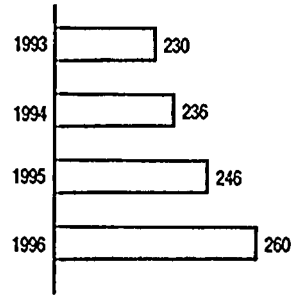


* Excludes Palo Verde sale and leaseback expense.

Number of Customers
1993 - 1996



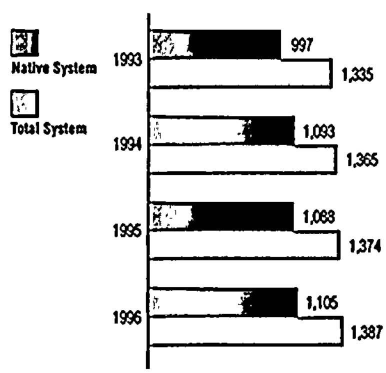
Number of Customers per Employee 1993 - 1996



Excellence in Operations

For a nuclear generating station to perform well, it must operate safely, efficiently and at a high level of utilization. The Palo Verde Nuclear Generating Station received an overall 1.25 SALP rating from the NRC as well as the highest rating of 1.0 from INPO in 1996. Operations and maintenance expenses declined 8.1% in 1996, while capacity factors continue to increase. The Company owns a 15.8% interest in each of the three units at Palo Verde. Palo Verde is operated by Arizona Public Service Company.

Peak Load

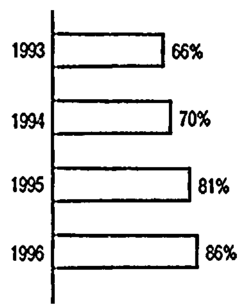


Nuclear Regulatory Commission
Systematic Assessment of Licensee Performance*

Operations	1
Maintenance	1
Engineering	1
Plant Support	2
Overall	1.25

* For period December 1, 1994 thru June 1, 1996

Palo Verde Capacity Factors
1993 - 1996



Operating Statistics

Operating revenues (In thousands):	1996 (1)	1995	1994	1993
Base revenues				
Retail:				
Residential	$ 141,719	$ 128,295	$ 129,869	$ 123,706
Commercial and Industrial, small	138,910	128,715	126,450	120,084
Commercial and Industrial, large	43,483	40,870	39,754	36,440
Sales to public authorities	65,534	59,613	59,811	57,063
Total retail	389,646	357,493	355,884	337,293
Wholesale sales for resale	71,254	74,557	75,750	89,863
Total base revenues	460,900	432,050	431,634	427,156
Fuel revenues and economy sales	114,042	68,823	101,076	112,005
Other	3,981	3,744	4,050	4,433
Total operating revenues	$ 578,923	$ 504,617	$ 536,760	$ 543,594
Number of customers (End of Year):				
Residential	250,209	245,245	240,368	235,151
Commercial and industrial, small	25,304	24,615	23,857	23,338
Commercial and industrial, large	102	89	80	74
Other	3,711	3,674	3,470	3,395
Total	279,326	273,623	267,775	261,958
Average annual use and revenue per residential customer:				
kWh	6,238	6,057	6,313	6,142
Revenue	$ 661.04	$ 578.88	$ 644.82	$ 637.68
Average revenue per kWh				
Residential	10.60 ¢	9.56 ¢	10.21 ¢	10.38 ¢
Commercial and industrial, small	9.21	8.15	8.88	9.12
Commercial and industrial, large	4.85	4.34	5.01	5.79
Energy supplied, net, kWh (In thousands):				
Generated	7,920,675	7,439,404	7,018,423	6,625,162
Purchased and interchanged	711,791	584,853	1,051,251	1,416,172
Total	8,632,466	8,024,257	8,069,674	8,041,334
Energy sales, kWh (In thousands):				
Retail:				
Residential	1,545,274	1,473,349	1,500,426	1,424,935
Commercial and industrial, small	1,779,986	1,754,176	1,721,736	1,616,434
Commercial and industrial, large	1,216,941	1,121,329	1,092,028	872,477
Sales to public authorities	1,110,706	1,068,048	1,081,850	1,034,231
	5,652,907	5,416,902	5,396,040	4,948,077
Wholesale:				
Sales for resale	1,753,553	1,646,357	1,925,671	2,484,128
Economy sales	757,999	538,102	320,026	164,559
Total sales	8,164,459	7,601,361	7,641,737	7,596,764
Losses and company use	468,007	422,896	427,937	444,570
Total	8,632,466 (2)	8,024,257 (2)	8,069,674 (2)	8,041,334
Native system:				
Peak load, kW	1,105,000	1,088,000	1,093,000	997,000
Net generating capacity for peak, kW	1,500,000	1,500,000	1,497,000	1,497,000
Load factor	63.4 %	61.6 %	61.1 %	62.1 %
Total System:				
Peak load, kW	1,387,000	1,374,000	1,365,000	1,335,000
Net generating capacity for peak, kW	1,500,000	1,500,000	1,497,000	1,497,000
Load factor	64.2 %	62.0 %	63.7 %	66.4 %

(1) Financial data is based on the combined results for the Predecessor Company for the period January 1, 1996 to February 11, 1996 and the Reorganized Company for the period February 12, 1996 to December 31, 1996.

(2) Includes unbilled kWh

1992	1991	1990	1989	1988	1987
$ 124,805	$ 109,891	$ 101,307	$ 97,381	$ 90,733	$ 79,889
120,793	104,794	94,117	89,043	80,449	69,783
38,693	35,592	30,170	27,986	23,631	20,752
57,780	51,200	47,425	46,046	41,390	35,384
342,071	301,477	273,019	260,456	236,203	205,808
80,663	54,095	49,918	52,272	57,223	59,947
422,734	355,572	322,937	312,728	293,426	265,755
98,451	103,810	119,525	118,305	104,499	76,312
3,575	3,023	2,847	2,437	3,945	1,573
$ 524,760	$ 462,405	$ 445,309	$ 433,470	$ 401,870	$ 343,640
228,688	223,684	218,753	214,664	209,550	204,102
22,883	22,417	22,135	21,762	21,069	20,582
68	68	60	52	39	41
3,251	3,156	2,788	2,659	2,543	2,505
254,890	249,325	243,736	239,137	233,201	227,230
6,169	6,063	6,082	6,124	6,025	5,846
$ 636.93	$ 588.11	$ 582.35	$ 577.60	$ 546.13	$ 511.48
10.32¢	9.70¢	9.57¢	9.43¢	9.07¢	8.75¢
9.14	8.44	8.21	8.08	7.52	7.28
5.61	5.55	5.65	5.53	5.10	5.19
7,330,004	6,128,171	5,277,127	4,753,236	4,904,854	3,186,967
589,288	1,273,440	1,726,525	1,794,492	2,079,665	2,594,170
7,919,292	7,401,611	7,003,652	6,547,728	6,984,519	5,781,137
1,395,387	1,342,830	1,318,471	1,299,768	1,246,081	1,179,812
1,555,047	1,511,550	1,484,207	1,450,817	1,397,913	1,316,198
911,750	864,025	784,177	763,650	697,758	635,448
997,483	956,691	954,441	947,948	908,238	860,852
4,859,667	4,675,096	4,541,296	4,462,183	4,249,990	3,992,310
2,361,204	1,717,850	1,442,799	1,411,162	1,271,366	1,087,444
264,654	637,425	640,399	348,429	1,109,872	329,215
7,485,525	7,030,371	6,624,494	6,221,774	6,631,228	5,408,969
433,767	371,240	379,158	325,954	353,291	372,168
7,919,292	7,401,611	7,003,652	6,547,728	6,984,519	5,781,137
974,000	929,000	920,000	916,000	840,000	820,000
1,497,000	1,497,000	1,497,000	1,497,000	1,497,000	1,297,000
62.3%	62.6%	61.6%	61.0%	63.0%	61.5%
1,302,000	1,142,000	1,098,000	1,076,000	1,002,000	975,000
1,497,000	1,497,000	1,497,000	1,497,000	1,497,000	1,297,000
66.4%	67.9%	66.7%	67.0%	67.3%	64.4%

Financial Forecast
Highlights

Tessie Alvarado, Customer Services Department

Ignacio Saucedo, Distribution Construction Department

Financial Forecast Highlights

The following forward looking statements are presented under section 21E of the Securities Exchange Act of 1934 and under Section 27A of the Securities Act of 1933. Actual results could differ substantially and materially from what we have projected. El Paso Electric Company cautions that factors such as sales growth, contractual agreements with the CFE and resolution of litigation related to the City of Las Cruces could cause actual results to differ materially from the projections. The Company cautions that the foregoing list of factors is not exclusive. The Company does not undertake to update any forward-looking statement that may be made from time to time by or on behalf of the Company.

(dollars in millions)	1997	1998	1999	2000	2001
Energy Sales (GWh)					
Retail	5,730	5,862	5,928	6,046	6,179
Sales for Resale	1,812	1,826	781	796	808
Economy	405	338	556	563	468
Construction	$49.9	$51.6	$50.2	$54.4	$50.2
Depreciation & Amortization	$89.1	$90.4	$92.5	$93.1	$93.3
Cash Federal & State Income Taxes	$(18.4)	$2.9	$3.0	$3.2	$4.2
Taxes other than Income (1)	$45.0	$46.6	$47.2	$48.3	$49.6

(1)Taxes other than income consist primarily of: property taxes, franchise taxes, payroll taxes and revenue related taxes.

Continued Deleveraging

Deleveraging the balance sheet is a significant, driving objective for El Paso Electric in 1997. The short-term incentive bonuses for all employees, established by the board in early 1997, are contingent upon the achievement of established goals for safety, customer satisfaction and deleveraging. However, no short-term incentive awards will be granted unless the deleveraging goals are met.

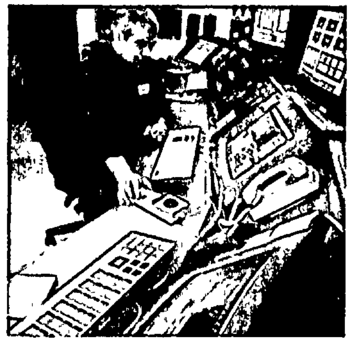
1996 provided a solid foundation from which to pursue this goal. During the year, the Company repurchased $118 million of its first mortgage bonds through open market purchases, which reduced the debt component of the capital structure from 74.8% in February to 70.9% at year end.

El Paso Electric believes continued substantial deleveraging is achievable during 1997 because it anticipates continued strong cash flow. Growth in revenues is expected to continue. Additionally, the Company does not anticipate paying income taxes due to the significant net operating loss carryforward generated upon emerging from bankruptcy. 1997 cash flow will also benefit from a decline in budgeted operation and maintenance levels and the renewal of the CFE contract for the year. In 1997, significant cash flow has already allowed the Company to repurchase approximately $50 million of its first mortgage bonds toward its goal of $123-$140 for the year. Achievement of this target should result in a capital structure with approximately 65% debt at year end 1997.

Shareholder Information

Elizabeth Flores, Customer Services Department

Charlie Villanueva, Distribution Operations Department



Isaac Villalobos, Power Generation Department

Securities and Records

The common stock of El Paso Electric Company is traded on the American Stock Exchange. The ticker symbol is EE.

El Paso Electric and The Bank of New York (BONY) act as co-transfer agents and co-registrars for the Company's common and preferred stock. BONY maintains all shareholder records of the Company.

Form 10-K Report and Shareholder Inquiries

A complete copy of El Paso Electric's Annual Report on Form 10-K for the year ended December 31,1996, which has been filed with the Securities and Exchange Commission, including Financial Statements and Financial Statement schedules is available without charge upon written request to:

Investor Relations
El Paso Electric
P.O. Box 982
El Paso, TX 79960
Or call: 800-592-1634
Email: epecfs02@whc.net

Shareholder Information

Shareholders may obtain information relating to their share position, transfer requirements, lost certificates, and other related matters by telephoning BONY Shareholder Services at 800-524-4458. This service is available to all shareholders Monday through Friday, 8 a.m. to 6 p.m., ET.

Address Shareholder Inquiries To:

The Bank of New York
Shareholder Relations Dept.
Church Street Station
P.O. Box 11258
New York, NY 10286-1258

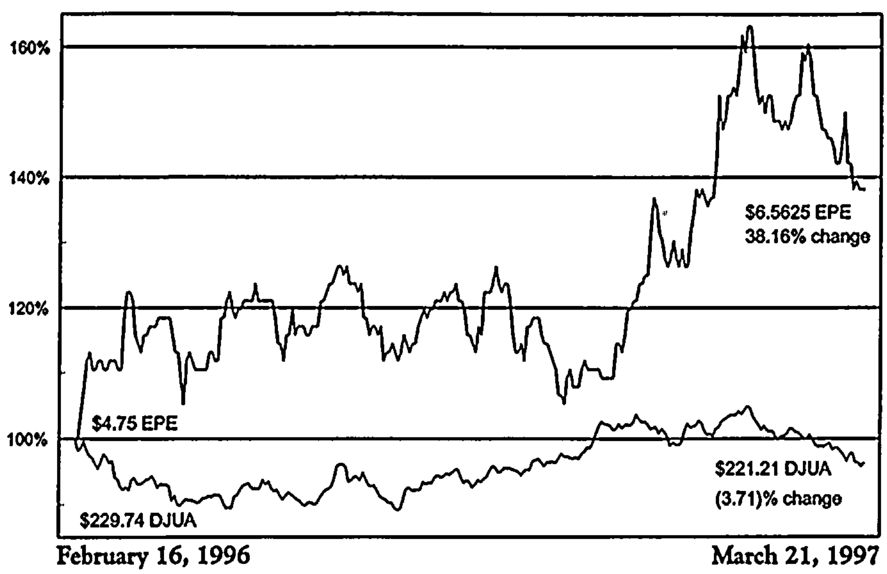
Send Certificates For Transfer and Address Changes To:

The Bank of New York
Receive and Deliver Dept.
Church Street Station
P.O. Box 11002
New York, NY 10286-1002

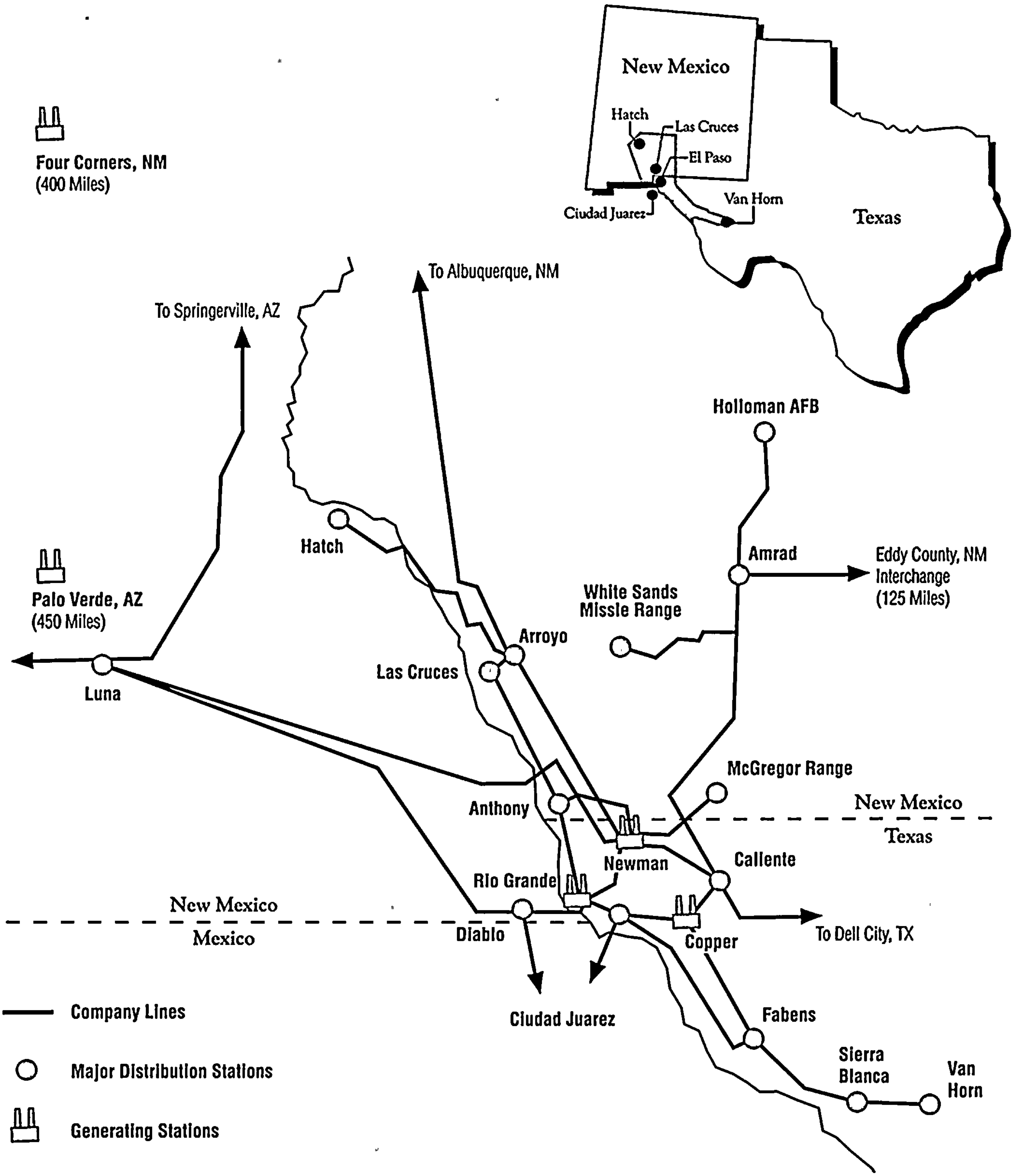
Annual Meeting of Shareholders

The annual meeting of El Paso Electric will be held in the Paul Kayser Center, 100 N. Stanton, El Paso, Texas, 79901, on Thursday, May 8, 1997 at 10 a.m., mountain daylight time. In connection with this meeting, proxies will be solicited by the Board of Directors of El Paso Electric. A notice of the meeting, together with a proxy statement, a form of proxy and the Annual Report to Shareholders for 1996, were mailed on or about April 7, 1997, to shareholders of record as of March 14, 1997.

Relative Performance EPE Common Stock and Dow Jones Utility Average



Service Area Map



SOUTHERN CALIFORNIA
EDISON

A Profile of Southern California Edison Company

Southern California Edison (SCE) is the nation's second-largest electric utility, based on the number of customers. Headquartered in Rosemead, California, SCE is a subsidiary of Edison International, which is primarily an energy-services company.

SCE, a 110-year-old investor-owned utility, serves 4.2 million customers in Central and Southern California. More than 11 million people live in its 50,000-square-mile service territory.

Contents

Selected Financial and Operating Data: 1992-1996

Southern California Edison Company

Dollars in millions	1996	1995	1994	1993	1992
Income statement data:					
Operating revenue	$ 7,583	$ 7,873	$ 7,799	$ 7,397	$ 7,722
Operating expenses	6,450	6,724	6,705	6,232	6,492
Fuel and purchased power expenses	3,336	3,197	3,403	3,290	3,086
Income tax from operations	578	560	508	506	520
Allowance for funds used during construction	25	34	29	36	37
Interest expense—net	453	464	443	449	517
Net income	655	680	639	678	673
Earnings available for common stock	621	643	599	637	631
Ratio of earnings to fixed charges	3.54	3.52	3.43	3.39	3.16
Balance sheet data:					
Assets	$17,737	$18,155	$18,076	$18,098	$15,969
Gross utility plant	21,134	20,717	20,127	19,441	18,652
Accumulated provision for depreciation and decommissioning	9,431	8,569	7,710	7,138	6,544
Common shareholder's equity	5,045	5,144	5,039	4,932	4,775
Preferred stock:					
Not subject to mandatory redemption	284	284	359	359	359
Subject to mandatory redemption	275	275	275	275	278
Long-term debt	4,779	5,215	4,988	5,234	5,184
Capital structure:					
Common shareholder's equity	48.6%	47.1%	47.3%	45.7%	45.1%
Preferred stock:					
Not subject to mandatory redemption	2.7%	2.6%	3.3%	3.3%	3.4%
Subject to mandatory redemption	2.7%	2.5%	2.6%	2.5%	2.6%
Long-term debt	46.0%	47.8%	46.8%	48.5%	48.9%
Operating data:					
Peak demand in megawatts (MW)	18,207	17,548	18,044	16,475	18,413
Generation capacity at peak (MW)	21,602	21,603	20,615	20,606	20,712
Kilowatt-hour sales (kWh) (in millions)	75,572	74,296	77,986	73,308	74,186
Average annual kWh sales per residential customer	6,322	6,188	6,259	6,070	6,311
Total energy requirement (kWh) (in millions)	84,236	81,924	85,011	81,328	82,199
Energy mix:					
Thermal	47.6%	51.6%	59.5%	53.8%	59.8%
Hydro	6.9%	7.7%	3.9%	7.3%	3.4%
Purchased power and other sources	45.5%	40.7%	36.6%	38.9%	36.8%
Customers (in millions)	4.22	4.18	4.15	4.12	4.11
Full-time employees*	12,057	14,886	16,351	16,585	16,922

*1992-1994 are based on twelve-month averages.

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Management's Discussion and Analysis of Results of Operations and Financial Condition

In the following Management's Discussion and Analysis of Results of Operations and Financial Condition and elsewhere in this annual report, the words "estimates," "expects," "anticipates," "believes," and other similar expressions, are intended to identify forward-looking information that involves risks and uncertainties. Actual results or outcomes could differ materially as a result of such important factors as the outcome of state and federal regulatory proceedings affecting the restructuring of the electric utility industry, the impacts of new laws and regulations relating to restructuring and other matters, the effects of increased competition in the electric utility business, and changes in prices of electricity and costs for fuel.

Results of Operations

Earnings

Southern California Edison Company's (SCE) 1996 earnings were $621 million, compared with $643 million in 1995 and $599 million in 1994. Included in earnings are special charges of $18 million in 1996, $15 million in 1995 and $18 million in 1994, primarily related to workforce management costs. Excluding special charges, SCE's 1996 earnings decreased $19 million over 1995. The decreased earnings are primarily attributable to a reduction in authorized rates of return and operating expenses, partially offset by improved operating performance. Excluding special charges, SCE's 1995 earnings increased $41 million over 1994, primarily due to a higher authorized return on common equity for 1995, partially offset by the financial effect of the 1995 general rate case settlement.

Operating Revenue

Operating revenue decreased 4% from 1995, as increased sales volume was offset by lower average rates. The lower rates are attributable to the California Public Utilities Commission's (CPUC) decision to lower SCE's 1996 authorized revenue by 4.4%. Additionally, during 1996 SCE issued a one-time bill credit of $237 million to ratepayers as part of a CPUC-ordered refund of energy-cost balancing account overcollections. Operating revenue in 1995 increased slightly over 1994, mainly due to a 2.6% CPUC-authorized rate increase, partially offset by a decrease in sales volume to resale cities and milder weather in 1995. In 1996, over 98% of operating revenue was from retail sales. Retail rates are regulated by the CPUC and wholesale rates are regulated by the Federal Energy Regulatory Commission (FERC).

Due to warm weather during the summer months, operating revenue during the third quarter of each year is materially higher than the other quarters.

The changes in operating revenue resulted from:

In millions	Year ended December 31,	1996	1995	1994
Operating revenue—				
Rate changes		$ (522)	$ 168	$ 112
Sales volume changes		206	(129)	308
Other		26	35	(18)
Total		$ (290)	$ 74	$ 402

In March 1995, SCE announced its intention to freeze average rates for residential, small business and agricultural customers through 1996, and announced a five-year goal to reduce system average rates by 25% on an inflation-adjusted basis (from 10.7¢ per kilowatt-hour to below 10¢ per kilowatt-hour). In February 1996, the CPUC approved a system-wide rate reduction which will drop the average price per kilowatt-hour from 10.7¢ to 10.1¢. Legislation enacted in September 1996 provides for, among other things, at least a 10% rate reduction for residential and small commercial customers beginning in 1998 (see discussion under Competitive Environment).

Operating Expenses

Fuel expense increased slightly in 1996 due to higher gas prices and changes in the fuel mix. Fuel expense decreased 27% in 1995 from 1994, since hydro generation was up significantly in 1995 due to greater rainfall, resulting in lower gas purchases. In addition, the San Onofre Nuclear Generating Station units were out of service a total of five months in 1995 for refueling and maintenance, causing a decrease in nuclear fuel expense. Lower overall gas prices in 1995 also contributed to the decrease in energy costs.

Purchased-power expense increased slightly in 1996 and 1995, due to an increase in power purchased under federally mandated contracts. SCE is required under federal law to purchase power from certain nonutility generators even though energy prices under these contracts are generally higher than other sources. In 1996, SCE paid about $1.7 billion (including energy and capacity payments) more for these power purchases than the cost of power available from other sources. The CPUC has mandated the prices for these contracts.

Provisions for regulatory adjustment clauses decreased substantially in 1996, compared to 1995. The decrease is mainly due to the energy-cost balancing account-related refund as discussed above, lower base rate revenue and undercollections related to the accelerated recovery of SCE's remaining investment in San Onofre Units 2 and 3 (see discussion in Note 1 to the Consolidated Financial Statements). The provisions increased in 1995, as CPUC-authorized fuel and purchased-power cost estimates exceeded actual energy costs. Actual energy costs were lower than estimated in 1995, due to the increase in hydro generation and lower gas prices.

Other operating expenses declined in both 1996 and 1995, due to ongoing cost reduction efforts and improved operating performance.

Maintenance expense decreased 8% in 1996, due to lower overall costs at SCE's generation, transmission and distribution operating facilities. Maintenance expense increased 8% in 1995, due to higher expenses related to the scheduled refueling and maintenance outages at San Onofre Units 2 and 3.

Depreciation and decommissioning expense increased 12% in 1996. The change is due to higher depreciation rates and the accelerated recovery of San Onofre Units 2 and 3.

Income taxes increased slightly during 1996, mainly due to an increase in deferred taxes resulting from the accelerated recovery of San Onofre Units 2 and 3.

Other Income and Deductions

The provision for rate phase-in plan reflects a CPUC-authorized, 10-year rate phase-in plan, which deferred the collection of revenue during the first four years of operation for the Palo Verde Nuclear Generating Station. The deferred revenue (including interest) is being collected evenly over the final six years of each unit's plan. The plan ended in February 1996 and September 1996 for Units 1 and 2, respectively. The plan ends in January 1998 for Unit 3. The provision is a non-cash offset to the collection of deferred revenue.

Other nonoperating income decreased substantially in 1996, compared to 1995, primarily due to additional accruals for regulatory matters. Other nonoperating income decreased in 1995, as CPUC-authorized incentive awards were below 1994 levels.

Interest Expense

Other interest expense decreased in 1996, due to the lower levels of short-term debt and lower interest rates. Other interest expense increased 30% in 1995, due to higher interest rates and higher balances in the regulatory balancing accounts.

Financial Condition

SCE's liquidity is primarily affected by debt maturities, dividend payments and capital expenditures. Capital resources include cash from operations and external financings.

In June 1994, SCE lowered its quarterly common stock dividend to its parent, Edison International, by 30%, due to the uncertainty of future earnings levels arising from the changing nature of California's electric utility regulation.

Management's Discussion and Analysis of Results of Operations and Financial Condition

Currently, Edison International has authorized the repurchase of up to $800 million of its common stock. Edison International has repurchased 27.4 million shares ($497 million) through January 31, 1997, funded by dividends from its subsidiaries and its lines of credit. As excess cash becomes available, SCE intends to pay cash dividends to Edison International, while maintaining its CPUC-authorized capital structure.

SCE's cash flow coverage of dividends during 1996 decreased to 2.2 times from 3.5 times in 1995 and 3.1 times in 1994, due to the additional cash needs of Edison International for debt repayment and other cash needs.

Cash Flows from Operating Activities

Net cash provided by operating activities totaled $1.8 billion in 1996, $2.0 billion in 1995 and $1.8 billion in 1994. Cash from operations exceeded capital requirements for all years presented.

Cash Flows from Financing Activities

Short-term debt is used to finance fuel inventories, balancing account undercollections and general cash requirements. Long-term debt is used mainly to finance capital expenditures. External financings are influenced by market conditions and other factors, including limitations imposed by its articles of incorporation and trust indenture. As of December 31, 1996, SCE could issue approximately $7.9 billion of additional first and refunding mortgage bonds and $4.5 billion of preferred stock at current interest and dividend rates.

At December 31, 1996, SCE had available lines of credit of $1.1 billion, with $600 million for short-term debt and $500 million for the long-term refinancing of its variable-rate pollution-control bonds. These unsecured lines of credit are at negotiated or bank index rates with various expiration dates; the majority have five-year terms.

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates. Additionally, the CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1996, SCE had the capacity to pay $112 million in additional dividends and continue to maintain its authorized capital structure.

Cash Flows from Investing Activities

The primary uses of cash for investing activities are additions to property and plant and funding of nuclear decommissioning trusts. Decommissioning costs are accrued and recovered in rates over the term of each nuclear generating facility's operating license through charges to depreciation expense. SCE estimates that it will spend approximately $12.7 billion between 2013-2070 to decommission its nuclear facilities. This estimate is based on SCE's current-dollar decommissioning costs ($2.0 billion), escalated using a 6.65% annual rate. These costs are expected to be funded from independent decommissioning trusts which receive SCE contributions of approximately $100 million per year until decommissioning begins.

Projected Capital Requirements

SCE's projected construction expenditures for the next five years are: 1997--$802 million; 1998--$636 million; 1999--$664 million; 2000--$647 million; and 2001--$650 million.

Long-term debt maturities and sinking fund requirements for the next five years are: 1997--$501 million; 1998-$447 million; 1999--$155 million; 2000--$325 million; and 2001--$400 million.

Regulatory Matters

SCE's 1997 CPUC-authorized rates remain unchanged from 1996 levels due to the recently enacted legislation which requires that system average rates remain frozen at the June 10, 1996, level of 10.1¢ per kilowatt-hour (see discussion in Competitive Environment).

The CPUC's 1997 cost-of-capital decision authorized an 11.6% return on common equity and a 48% common equity ratio, both unchanged from 1996 levels. SCE's return on rate base was lowered from 9.55% to 9.49%. The decision, excluding the effects of other rate actions, would reduce 1997 earnings by approximately $5 million.

A 1994 CPUC decision stated that SCE was liable for expenditures related to a 1985 accident at the Mohave Generating Station. In July 1996, the CPUC approved a settlement agreement between SCE and the Office of Ratepayer Advocates (ORA) which resulted in a $39 million (including interest) refund to SCE's customers. The refund, which had been previously reserved, was completed by year-end 1996.

In May 1994, SCE filed its testimony in the non-Qualifying Facilities phase of the 1994 Energy Cost Adjustment Clause proceeding. In May 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommends a disallowance of $13.3 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requests that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In October 1996, the ORA issued its report for the 1995 record period recommending a $37.6 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances have been consolidated into one proceeding. SCE and the ORA have filed several rounds of testimony on this issue. Hearings began in January 1997 and are expected to conclude in February 1997. A decision is expected in late 1997.

On December 23, 1996, the CPUC issued a final decision on SCE's proposal for a new rate mechanism for its 15.8% share of the three units at Palo Verde. The decision adopts the Palo Verde All-Party Settlement filed with the CPUC on November 15, 1996. The settlement was based on a Memorandum of Understanding signed by all of the active parties to the Palo Verde proceeding. Under the settlement, SCE has the opportunity to recover its remaining investment (approximately $1.2 billion) in Palo Verde beginning January 1, 1997, and ending December 31, 2001, earning a reduced rate of return on rate base of 7.35% instead of the current 9.49%. Also, SCE will utilize a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable as long as they do not exceed 30% of a baseline forecast and the site's gross annual capacity factor does not go below 55%) to ratepayers. Beginning January 1, 1998, this balancing account will become part of the competition transition charge (CTC) mechanism. If SCE's actual costs are less than the forecast, the difference will benefit ratepayers as a credit to the CTC mechanism. The existing nuclear unit incentive procedure will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle. After 2001, SCE's ratepayers will receive 50% of the benefits derived from the operation of Palo Verde. The decision is projected to reduce SCE's 1997 earnings by approximately $21 million.

Competitive Environment

SCE currently operates in a highly regulated environment in which it has an obligation to provide electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing. The generation sector has experienced competition from nonutility power producers and regulators are restructuring California's electric utility industry.

On September 23, 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopts the CPUC's December 1995 restructuring decision (discussed below) by addressing stranded-cost recovery for utilities, providing a certain cost recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also includes provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, thereby allowing SCE to give a rate reduction of at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation includes a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement based on cost-of-service regulation during the 1998-2001 transition period. In addition, the legislation mandates the implementation of a non-bypassable CTC that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contains provisions for the recovery (through 2006) of reasonable employee-related transition costs incurred and projected for retraining, severance, early retirement, outplacement and related expenses for utility workers. In light of the legislation, the CPUC is reassessing the need to prepare an environmental impact report.

In December 1995, the CPUC issued its decision on restructuring California's electric utility industry. The transition to a new market structure, which is expected to provide competition and customer choice, would begin January 1, 1998, with all consumers participating by 2003 (changed to 2002 by the recently enacted legislation). Key elements of the CPUC decision include:

- Creation of an independent power exchange (PX) to manage electric supply and demand. California's investor-owned utilities would be required to purchase from and sell to the exchange all of their power during the transition period, while other generators could voluntarily participate.

- Creation of an independent system operator (ISO) to have operational control of the utilities' transmission facilities and, therefore, control the scheduling and dispatch of all electricity on the state's power grid.

- Availability of customer choice through time-of-use rates, direct customer access to generation providers with transmission arrangements through the system operator, and customer-arranged "contracts for differences" to manage price fluctuations from the PX.

- Recovery of costs to transition to a competitive market (utility investments, obligations incurred to serve customers under the existing framework and reasonable employee-related costs) through a non-bypassable charge, applied to all customers, called the CTC.

- CPUC-established incentives to encourage voluntary divestiture (through spin-off or sale to an unaffiliated entity) of at least 50% of utilities' gas-fueled generation to address market power issues.

- Performance-based ratemaking (PBR) for those utility services not subject to competition.

In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. On November 26, 1996, the FERC conditionally accepted the proposal and directed the three utilities to file more specific information by March 31, 1997. In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans would be backed by utility guarantees; SCE's share would be 45%. Once the ISO and PX are formed, they will repay the trust's loans and recover funds from future ISO and PX customers. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million which will be used to build the hardware and software systems for the ISO and PX.

Recovery of costs to transition to a competitive market would be implemented through a non-bypassable CTC. This charge would apply to all customers who were using or began using utility services on or after the December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e., after subtracting other cost components for the PX, transmission and distribution (T&D), nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value), assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value), assuming the fossil plants have no market value. These estimates are based on incurred costs, and forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of:

$7.5 billion from SCE's qualifying facility contracts, which are the direct result of legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed-through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre (as discussed in Note 1 to the Consolidated Financial Statements) and Palo Verde, nuclear decommissioning and certain other costs.

On November 27, 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all of its oil- and gas-fueled generation assets. This application builds on SCE's March 1996 plan which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the recent restructuring legislation. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. CPUC approval of the oil- and gas-fueled generation divestiture was requested for late 1997.

In September 1996, the CPUC adopted a non-generation T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC decision, beginning in 1998, the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; adjustments for cost changes that are not within SCE's control; a cost of capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations. In July 1996, SCE filed a PBR proposal for its hydroelectric plants and a proposed structure for performance-based local reliability contracts for certain fossil-fueled plants. If approved, the hydro PBR would be in effect for three years and the initial terms of the local reliability contracts, which are subject to FERC approval, would be in effect for up to three years, both beginning January 1, 1998. A final CPUC decision on hydro PBR is expected by year-end 1997.

In July 1996, SCE filed a proposal with the CPUC related to the conceptual aspects of separating the costs associated with generation, transmission, distribution, public benefit programs and the CTC. The filing was in response to CPUC and FERC directives which require electric services, such as T&D, to be functionally separate and available to all customers on a nondiscriminatory basis without cost-shifting among customers. On December 6, 1996, SCE filed a more comprehensive plan for the functional unbundling of SCE's rates for electric service, beginning on January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates in separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The filing also included proposals for establishing new regulatory proceedings to replace current proceedings that will no longer be necessary during the rate freeze period.

Although depreciation-related differences could result from applying a regulatory prescribed depreciation method (straight-line, remaining-life method) rather than a method that would have been applied absent the regulatory process, SCE believes that the depreciable lives of its generation-related assets would not vary significantly from that of an unregulated enterprise, as the CPUC bases depreciable lives on periodic studies that reflect the physical useful lives of the assets. SCE also believes that any depreciation-related differences would be recovered through the CTC.

If events occur during the restructuring process that result in all or a portion of the CTC being improbable of recovery, SCE could have write-offs associated with these costs if they are not recovered through another regulatory mechanism. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or implementation phases, or the effect, after the transition period, that competition will have on its results of operations or financial position.

Subsequent Event

If the CPUC's restructuring is implemented as outlined, SCE would be allowed to recover its CTC (subject to a lower return on equity) and believes it should be allowed to continue to apply accounting standards that recognize the economic effects of rate regulation for its generation-related assets during the 1998-2001 transition period. However, in response to a request by the staff of the Securities and Exchange Commission (SEC), in December 1996, SCE submitted its views on the continued applicability of regulatory accounting standards for its generation-related assets. In its submittal, SCE and its independent accountants jointly concluded that, based on their current analysis, SCE will continue to meet the criteria for applying these accounting standards through the 1998-2001 transition period. In its February 1997 response, the SEC staff expressed continuing concern with SCE's conclusion and indicated that they wanted to meet further with SCE and the other major California electric utilities to resolve this matter. SCE and its independent accountants continue to believe that SCE meets such criteria and plan to meet with the SEC staff to present additional and clarifying information seeking to convince the SEC staff of the merits of SCE's position. The authority to require SCE to discontinue applying regulatory accounting standards rests with the SEC. If SCE is required to discontinue the application of these accounting standards for its generation-related assets, it would have to write off generation-related regulatory assets, which at December 31, 1996, totaled approximately $600 million on an after-tax basis, primarily for the recovery of income tax benefits previously flowed-through to customers, the Palo Verde phase-in plan and unamortized loss on reacquired debt.

SCE believes that a proper application of regulatory accounting standards will result in it no longer meeting the criteria to apply these accounting standards to all of its non-hydroelectric generation-related assets after the end of the 1998-2001 transition period. If SCE continues the application of these accounting standards during the transition period, but during the transition period events occur that result in SCE no longer meeting the criteria for applying such standards, SCE may be required to write off the remaining balance of its recorded generation-related regulatory assets existing at that time.

If a non-cash write-off is required, SCE believes that it should not affect the stranded-cost recovery plans set forth in the CPUC's December 1995 restructuring decision and legislation enacted by the State of California in September 1996.

FERC Stranded Cost/Open Access Transmission Decision

In April 1996, the FERC issued its decision on stranded cost recovery and open access transmission, effective July 1996. The decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the recovery of stranded costs, which are prior-service costs incurred under the current regulatory framework. In addition to providing recovery of stranded costs associated with existing wholesale customers, the FERC directed that it would have primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as the formation of a new municipal electric system. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states and the FERC would only address recovery of these costs if the state has no authority to do so. In compliance with the April 1996 FERC decision, SCE filed a revised open access tariff with the FERC in July 1996. The tariff became effective on an interim basis, subject to refund, as of its filing date. Several wholesale customers have filed protests with the FERC on the transmission rate levels, and a ruling from the FERC setting the rates to be decided at formal hearings is anticipated in early 1997.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

As further discussed in Note 10 to the Consolidated Financial Statements, SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site. Unless there is a probable amount, SCE records the lower end of this likely range of costs.

SCE's recorded estimated minimum liability to remediate its 55 identified sites was $114 million at December 31, 1996. One of SCE's sites, a former pole-treating facility, is considered a federal Superfund site and represents 71% of its recorded liability. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $211 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 35 of its sites, representing $101 million of its recorded liability, through an incentive mechanism. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with a number of its carriers. Costs incurred at the remaining 20 sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $104 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $8 million. Recorded costs for 1996 were $7 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not have a material adverse effect on its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

The 1990 federal Clean Air Act requires power producers to have emissions allowances to emit sulfur dioxide. Power companies receive emissions allowances from the federal government and may bank or sell excess allowances. SCE expects to have excess allowances under Phase II of the Clean Air Act (2000 and later). The act also calls for a study to determine if additional regulations are needed to reduce regional haze in the southwestern U.S. In addition, another study is in progress to determine the specific impact of air contaminant emissions from the Mohave Coal Generating Station on visibility in Grand Canyon National Park. The potential effect of these studies on sulfur dioxide emissions regulations for Mohave is unknown.

SCE's projected capital expenditures to protect the environment are $900 million for the 1997-2001 period, mainly for aesthetics treatment, including undergrounding certain transmission and distribution lines.

The possibility that exposure to electric and magnetic fields (EMF) emanating from power lines, household appliances and other electric sources may result in adverse health effects is receiving increased attention. The scientific community has not yet reached a consensus on the nature of any health effects of EMF. However, the CPUC has issued a decision which provides for a rate-recoverable research and public education program conducted by California electric utilities, and authorizes these utilities to take no-cost or low-cost steps to reduce EMF in new electric facilities. SCE is unable to predict when or if the scientific community will be able to reach a consensus on any health effects of EMF, or the effect that such a consensus, if reached, could have on future electric operations.

Palo Verde Steam Tube Rupture

In 1993, a steam generator tube ruptured at Palo Verde Unit 2; additional cracking was found in other tubes. Arizona Public Service Company (APS), the operating agent for Palo Verde, has taken, and will continue to take, remedial actions that it believes have slowed the rate of steam generator tube degradation in all three units. APS believes that the steam generators in only one of the units will have to be replaced within five to ten years. Based on APS' 100% share estimate, SCE estimates its share of the costs to be between $22 million and $24 million, plus replacement power costs. SCE is evaluating APS' analyses, conducting its own review, and has not yet decided whether it supports replacement of the steam generators.

Workforce Reductions

During 1996, SCE offered a voluntary retirement program to certain eligible employees. Approximately 3,000 employees (2,200 non-represented and 800 represented employees) accepted the terms of this program. After allowance for the effects of pension settlement gains, SCE's net expense for this program was $4 million.

Proposed New Accounting Standard

During 1996, the Financial Accounting Standards Board issued an exposure draft that would establish accounting standards for the recognition and measurement of closure and removal obligations. The exposure draft would require the estimated present value of an obligation to be recorded as a liability, along with a corresponding increase in the plant or regulatory asset accounts when the obligation is incurred. If the exposure draft is approved in its present form, it would affect SCE's accounting practices for the decommissioning of its nuclear power plants, obligations for coal mine reclamation costs and any other activities related to the closure or removal of long-lived assets. SCE does not expect that the accounting changes proposed in the exposure draft would have an adverse effect on its results of operations even after deregulation due to its current and expected future ability to recover these costs through customer rates.

Consolidated Statements of Income

In thousands Year ended December 31,	1996	1995	1994
Operating revenue	$7,583,382	$ 7,872,718	$ 7,798,601
Fuel	630,512	614,954	840,607
Purchased power	2,705,880	2,581,878	2,562,890
Provisions for regulatory adjustment clauses—net	(225,908)	229,744	54,772
Other operating expenses	1,178,316	1,226,534	1,315,249
Maintenance	329,371	356,693	330,161
Depreciation and decommissioning	1,063,505	954,141	890,656
Income taxes	578,329	559,694	507,626
Property and other taxes	190,284	200,236	202,711
Total operating expenses	6,450,289	6,723,874	6,704,672
Operating income	1,133,093	1,148,844	1,093,929
Provision for rate phase-in plan	(84,288)	(122,233)	(136,596)
Allowance for equity funds used during construction	15,579	19,082	14,348
Interest income	37,855	37,644	31,082
Other nonoperating income—net	(3,623)	45,651	64,597
Total other income (deductions)—net	(34,477)	(19,856)	(26,569)
Income before interest expense	1,098,616	1,128,988	1,067,360
Interest on long-term debt	380,812	385,187	381,827
Other interest expense	73,914	80,130	61,646
Allowance for borrowed funds used during construction	(9,794)	(14,489)	(14,440)
Capitalized interest	(1,711)	(1,531)	(254)
Total interest expense—net	443,221	449,297	428,779
Net income	655,395	679,691	638,581
Dividends on preferred stock	34,395	36,764	40,080
Earnings available for common stock	$ 621,000	$ 642,927	$ 598,501

Consolidated Statements of Retained Earnings

In thousands Year ended December 31,	1996	1995	1994
Balance at beginning of year	$2,780,058	$ 2,683,568	$ 2,586,890
Net income	655,395	679,691	638,581
Dividends declared on common stock	(735,429)	(545,672)	(501,823)
Dividends declared on preferred stock	(34,395)	(36,764)	(40,080)
Reacquired capital stock expense	(17)	(765)	-
Balance at end of year	$2,665,612	$ 2,780,058	$ 2,683,568

The accompanying notes are an integral part of these financial statements.

Consolidated Balance Sheets

In thousands December 31,	1996	1995
ASSETS		
Utility plant, at original cost	$20,400,387	$19,850,179
Less—accumulated provision for depreciation and decommissioning	9,431,071	8,569,265
	10,969,316	11,280,914
Construction work in progress	556,645	727,865
Nuclear fuel, at amortized cost	176,827	139,411
Total utility plant	11,702,788	12,148,190
Nonutility property—less accumulated provision for depreciation of $25,102 and $25,454 at respective dates	63,931	70,191
Nuclear decommissioning trusts	1,485,525	1,260,095
Other investments	103,973	65,963
Total other property and investments	1,653,429	1,396,249
Cash and equivalents	319,942	261,767
Receivables, including unbilled revenue, less allowances of $26,079 and $24,139 for uncollectible accounts at respective dates	921,083	911,963
Fuel inventory	72,480	114,357
Materials and supplies, at average cost	154,266	151,180
Accumulated deferred income taxes—net	240,429	476,725
Prepayments and other current assets	105,137	114,289
Total current assets	1,813,337	2,030,281
Unamortized debt issuance and reacquisition expense	346,834	350,563
Rate phase-in plan	50,703	129,714
Unamortized nuclear plant—net	-	67,185
Income tax-related deferred charges	1,741,091	1,723,605
Other deferred charges	428,370	309,328
Total deferred charges	2,566,998	2,580,395
Total assets	$17,736,552	$18,155,115

The accompanying notes are an integral part of these financial statements.

In thousands, except share amounts December 31,	1996	1995
CAPITALIZATION AND LIABILITIES		
Common shareholder's equity:		
Common stock (434,888,104 shares outstanding at each date)	$ 2,168,054	$ 2,168,054
Additional paid-in capital and other	210,857	195,815
Retained earnings	2,665,612	2,780,058
	5,044,523	5,143,927
Preferred stock:		
Not subject to mandatory redemption	283,755	283,755
Subject to mandatory redemption	275,000	275,000
Long-term debt	4,778,703	5,215,117
Total capitalization	10,381,981	10,917,799
Other long-term liabilities	423,925	344,192
Current portion of long-term debt	501,470	1,375
Short-term debt	230,149	359,508
Accounts payable	392,779	346,258
Accrued taxes	484,688	550,384
Accrued interest	93,363	86,494
Dividends payable	108,563	138,334
Regulatory balancing accounts—net	181,488	337,867
Deferred unbilled revenue and other current liabilities	825,317	778,476
Total current liabilities	2,817,817	2,598,696
Accumulated deferred income taxes—net	3,170,696	3,323,190
Accumulated deferred investment tax credits	347,118	374,142
Customer advances and other deferred credits	595,015	597,096
Total deferred credits	4,112,829	4,294,428
Commitments and contingencies (Notes 2, 8, 9 and 10)		
Total capitalization and liabilities	$17,736,552	$18,155,115

The accompanying notes are an integral part of these financial statements.

Consolidated Statements of Cash Flows

In thousands / Year ended December 31,	1996	1995	1994
Cash flows from operating activities:			
Net income	$ 655,395	$ 679,691	$ 638,581
Adjustments for non-cash items:			
Depreciation and decommissioning	1,063,505	954,141	890,656
Amortization	90,931	68,064	126,131
Rate phase-in plan	79,011	111,016	123,479
Deferred income taxes and investment tax credits	46,122	(208,671)	(95,218)
Other long-term liabilities	79,733	33,129	44,468
Other—net	(153,034)	(261)	(23,841)
Changes in working capital:			
Receivables	(9,120)	(9,873)	(64,311)
Regulatory balancing accounts	(156,379)	282,157	(2,222)
Fuel inventory, materials and supplies	38,791	(19,499)	(21,087)
Prepayments and other current assets	9,152	(15,511)	(1,260)
Accrued interest and taxes	(58,827)	34,704	117,819
Accounts payable and other current liabilities	93,362	45,355	89,682
Net cash provided by operating activities	1,778,642	1,954,442	1,822,877
Cash flows from financing activities:			
Long-term debt issued	396,309	393,829	964
Long-term debt repayments	(403,957)	(422,503)	(170,224)
Preferred stock redemptions	-	(75,000)	-
Nuclear fuel financing—net	41,803	31,134	(31,444)
Short-term debt financing—net	(129,359)	(316,006)	62,420
Dividends paid	(799,593)	(559,886)	(588,917)
Net cash used by financing activities	(894,797)	(948,432)	(727,201)
Cash flows from investing activities:			
Additions to property and plant	(616,427)	(772,950)	(981,894)
Funding of nuclear decommissioning trusts	(148,158)	(150,595)	(130,155)
Unrealized gain in equity investments	14,900	8,483	9,999
Other—net	(75,985)	(21,273)	(6,453)
Net cash used by investing activities	(825,670)	(936,335)	(1,108,503)
Net increase (decrease) in cash and equivalents	58,175	69,675	(12,827)
Cash and equivalents, beginning of year	261,767	192,092	204,919
Cash and equivalents, end of year	$ 319,942	$ 261,767	$ 192,092
Cash payments for interest and taxes:			
Interest	$ 348,691	$ 382,798	$ 365,126
Taxes	545,834	692,780	443,801

The accompanying notes are an integral part of these financial statements.

Note 1. Summary of Significant Accounting Policies

Southern California Edison Company's (SCE) outstanding common stock is owned entirely by its parent company, Edison International. SCE is a public utility which produces and supplies electric energy for its 4.2 million customers in Central and Southern California. The consolidated financial statements include SCE and its subsidiaries. Intercompany transactions have been eliminated.

SCE's accounting policies conform with generally accepted accounting principles (GAAP), including the accounting principles for rate-regulated enterprises which reflect the rate-making policies of the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC).

SCE currently operates in a highly regulated environment in which it has an obligation to provide electric service to customers in return for an exclusive franchise within its service territory. This regulatory environment is changing, as further discussed in Note 2 to the Consolidated Financial Statements. Financial statements prepared in compliance with GAAP require management to make estimates and assumptions that affect the amounts reported in the financial statements and disclosure of contingencies. Actual results could differ from those estimates. Certain significant estimates related to electric utility industry restructuring, decommissioning and contingencies, are further discussed in Notes 2, 9 and 10, respectively.

Certain prior-year amounts were reclassified to conform to the December 31, 1996, financial statement presentation.

Debt Issuance and Reacquisition Expense

Debt premium, discount and issuance expenses are amortized over the life of each issue. Under CPUC rate-making procedures, debt reacquisition expenses are amortized over the remaining life of the reacquired debt or, if refinanced, the life of the new debt.

Financial Instruments

SCE enters into interest rate swap and cap agreements to manage its interest rate exposure. Interest rate differentials and premiums for interest rate caps to be paid or received are recorded as adjustments to interest expense.

Fuel Inventory

Fuel inventory is valued under the last-in, first-out method for fuel oil and natural gas, and under the first-in, first-out method for coal.

Investments

Cash equivalents include tax-exempt investments ($261 million at December 31, 1996, and $235 million at December 31, 1995), and time deposits and other investments ($43 million at December 31, 1996, and $23 million at December 31, 1995) with maturities of three months or less.

Net unrealized gains (losses) in equity investments are recorded as a separate component of shareholder's equity under "Additional paid-in capital and other." Unrealized gains and losses on decommissioning trust funds are recorded in the accumulated provision for decommissioning.

All investments are classified as available-for-sale.

Nuclear

The CPUC authorized rate phase-in plans to defer the collection of $200 million in revenue for each unit at the Palo Verde Nuclear Generating Station during the first four years of operation and recover the deferred revenue (including interest) evenly over the following six years. The phase-in plans ended in February 1996 and September 1996 for Units 1 and 2, respectively. The plan ends in January 1998 for Unit 3.

Decommissioning costs are accrued and recovered in rates over the term of each nuclear facility's operating license through charges to decommissioning expense (see Note 9).

Under the Energy Policy Act of 1992, SCE is liable for its share of the estimated costs to decommission three federal nuclear enrichment facilities (based on purchases). These costs, which will be paid over 15 years, are recorded as a fuel cost and recovered through customer rates.

In August 1992, the CPUC approved a settlement agreement between SCE and the CPUC's Office (formerly Division) of Ratepayer Advocates (ORA) to discontinue operation of San Onofre Nuclear Generating Station Unit 1 at the end of its then-current fuel cycle because operation of the unit was no longer cost-effective. In November 1992, SCE discontinued operation of Unit 1. As part of the agreement, SCE recovered its remaining investment over a four-year period ending August 1996, earning an 8.98% rate of return on rate base.

In October 1994, the CPUC authorized accelerated recovery of SCE's nuclear plant investments by $75 million per year, with a corresponding deceleration in recovery of its transmission and distribution assets through revised depreciation estimates over their remaining useful lives.

In April 1996, the CPUC authorized, and SCE began accelerating, the recovery of its remaining investment of $2.6 billion in San Onofre Units 2 and 3. The accelerated recovery will continue through December 2001 (the original end date of 2003 was changed by legislation enacted in September 1996), earning a 7.35% fixed rate of return (compared to the current 9.49%). Future operating costs, including nuclear fuel and nuclear-fuel financing costs and incremental capital expenditures at San Onofre Units 2 and 3, are subject to an incentive pricing plan whereby SCE receives about 4¢ per kilowatt-hour through 2003. Any differences between these costs and the incentive price will flow through to the shareholders. Beginning in 2004, SCE will be required to share equally with ratepayers the benefits received from operation of the units.

Prior to January 1, 1997, the cost of nuclear fuel for Palo Verde, including disposal, was amortized to fuel expense on the basis of generation. Under CPUC rate-making procedures in effect for Palo Verde prior to January 1, 1997, nuclear-fuel financing costs were capitalized until the fuel was placed into production.

Regulatory Balancing Accounts

The differences between CPUC-authorized and actual base-rate revenue from kilowatt-hour sales and CPUC-authorized and actual energy costs are accumulated in balancing accounts until they are refunded to, or recovered from, utility customers through authorized rate adjustments (with interest). Income tax effects on balancing account changes are deferred.

Research, Development and Demonstration (RD&D)

SCE capitalizes RD&D costs that are expected to result in plant construction. If construction does not occur, these costs are charged to expense. RD&D expenses are recorded in a balancing account and, at the end of the rate-case cycle, any authorized but unspent RD&D funds are refunded to customers. RD&D expenses were $21 million in 1996, $28 million in 1995 and $63 million in 1994.

Revenue

Operating revenue includes amounts for services rendered but unbilled at the end of each year.

Stock-based Compensation

SCE measures compensation expense relative to stock-based compensation by the intrinsic-value method.

Utility Plant

Plant additions, including replacements and betterments, are capitalized. Such costs include direct material and labor, construction overhead and an allowance for funds used during construction (AFUDC). AFUDC represents the estimated cost of debt and equity funds that finance utility-plant construction. AFUDC is capitalized during plant construction and reported in current earnings. AFUDC is recovered in rates through depreciation expense over the useful life of the related asset. Depreciation of utility plant is computed on a straight-line, remaining-life basis. Replaced or retired property and removal costs less salvage are charged to the accumulated provision for depreciation. Depreciation expense stated as a percent of average original cost of depreciable utility plant was 4.2% for 1996, and 3.6% for both 1995 and 1994.

Note 2. Regulatory Matters

Electric Utility Industry Restructuring

On September 23, 1996, the State of California enacted legislation to provide a transition to a competitive market structure. The legislation substantially adopts the CPUC's December 1995 restructuring decision (discussed below) by addressing stranded-cost recovery for utilities, providing a certain cost recovery time period for the transition costs associated with utility-owned generation-related assets. Transition costs related to power-purchase contracts would be recovered through the terms of their contracts while most of the remaining transition costs would be recovered through 2001. The legislation also includes provisions to finance a portion of the stranded costs that residential and small commercial customers would have paid between 1998 and 2001, thereby allowing SCE to give a rate reduction of at least 10% to these customers, beginning January 1, 1998. The financing would occur with securities issued by the California Infrastructure and Economic Development Bank, or an entity approved by the Bank. The legislation includes a rate freeze for all other customers, including large commercial and industrial customers, as well as provisions for continued funding for energy conservation, low-income programs and renewable resources. Despite the rate freeze, SCE expects to be able to recover its revenue requirement based on cost-of-service regulation during the 1998-2001 transition period. In addition, the legislation mandates the implementation of a non-bypassable competition transition charge (CTC) that provides utilities the opportunity to recover costs made uneconomic by electric utility restructuring. Finally, the legislation contains provisions for the recovery (through 2006) of reasonable employee-related transition costs incurred and projected for retraining, severance, early retirement, outplacement and related expenses for utility workers. In light of the legislation, the CPUC is reassessing the need to prepare an environmental impact report.

In December 1995, the CPUC issued its decision on restructuring California's electric utility industry. The transition to a new market structure, which is expected to provide competition and customer choice, would begin January 1, 1998, with all consumers participating by 2003 (changed to 2002 by the recently enacted legislation). Key elements of the CPUC decision include:

- Creation of an independent power exchange (PX) to manage electric supply and demand. California's investor-owned utilities would be required to purchase from and sell to the exchange all of their power during the transition period, while other generators could voluntarily participate.

- Creation of an independent system operator (ISO) to have operational control of the utilities' transmission facilities and, therefore, control the scheduling and dispatch of all electricity on the state's power grid.

- Availability of customer choice through time-of-use rates, direct customer access to generation providers with transmission arrangements through the system operator, and customer-arranged "contracts for differences" to manage price fluctuations from the PX.

- Recovery of costs to transition to a competitive market (utility investments, obligations incurred to serve customers under the existing framework and reasonable employee-related costs) through a non-bypassable charge, applied to all customers, called the CTC.

- CPUC-established incentives to encourage voluntary divestiture (through spin-off or sale to an unaffiliated entity) of at least 50% of utilities' gas-fueled generation to address market power issues.

- Performance-based ratemaking (PBR) for those utility services not subject to competition.

In April 1996, SCE, Pacific Gas & Electric Company and San Diego Gas & Electric Company filed a proposal with the FERC regarding the creation of the PX and the ISO. On November 26, 1996, the FERC conditionally accepted the proposal and directed the three utilities to file more specific information by March 31, 1997. In July 1996, the three utilities jointly filed an application with the CPUC requesting approval to establish a restructuring trust which would obtain loans up to $250 million for the development of the ISO and PX through January 1, 1998. The loans would be backed by utility guarantees; SCE's share would be 45%. Once the ISO and PX are formed, they will repay the trust's loans and recover funds from future ISO and PX customers. In August 1996, the CPUC issued an interim order establishing the restructuring trust and the funding level of $250 million which will be used to build the hardware and software systems for the ISO and PX.

Recovery of costs to transition to a competitive market would be implemented through a non-bypassable CTC. This charge would apply to all customers who were using or began using utility services on or after the December 20, 1995, decision date. In August 1996, in compliance with the CPUC's restructuring decision, SCE filed its application to estimate its 1998 transition costs. In October 1996, SCE amended its transition cost filing to reflect the effects of the legislation enacted in September 1996. Under the rate freeze codified in the legislation, the CTC will be determined residually (i.e,, after subtracting other cost components for the PX, transmission and distribution (T&D), nuclear decommissioning and public benefit programs). Nevertheless, the CPUC directed that the amended application provide estimates of SCE's potential transition costs from 1998 through 2030. SCE provided two estimates between approximately $13.1 billion (1998 net present value), assuming the fossil plants have a market value equal to their net book value, and $13.8 billion (1998 net present value), assuming the fossil plants have no market value. These estimates are based on incurred costs, and forecasts of future costs and assumed market prices. However, changes in the assumed market prices could materially affect these estimates. The potential transition costs are comprised of: $7.5 billion from SCE's qualifying facility contracts, which are the direct result of legislative and regulatory mandates; and $5.6 billion to $6.3 billion from costs pertaining to certain generating plants and regulatory commitments consisting of costs incurred (whose recovery has been deferred by the CPUC) to provide service to customers. Such commitments include the recovery of income tax benefits previously flowed-through to customers, postretirement benefit transition costs, accelerated recovery of San Onofre (as discussed in Note 1) and Palo Verde, nuclear decommissioning and certain other costs.

On November 27, 1996, SCE filed an application with the CPUC to voluntarily divest, by auction, all of its oil- and gas-fueled generation assets. This application builds on SCE's March 1996 plan which outlined how SCE proposed to divest 50% of these assets. Under the new proposal, SCE would continue to operate and maintain the divested power plants for at least two years following their sale, as mandated by the recent restructuring legislation. In addition, SCE would offer workforce transition programs to those employees who may be impacted by divestiture-related job reductions. SCE's proposal is contingent on the overall electric industry restructuring implementation process continuing on a satisfactory path. CPUC approval of the oil- and gas-fueled generation divestiture was requested for late 1997.

In September 1996, the CPUC adopted a non-generation T&D PBR mechanism for SCE which began on January 1, 1997. According to the CPUC decision, beginning in 1998, the transmission portion is to be separated from non-generation PBR and subject to ratemaking under the rules of the FERC. The distribution-only PBR will extend through December 2001. Key elements of the non-generation PBR include: T&D rates indexed for inflation based on the Consumer Price Index less a productivity factor; elimination of the kilowatt-hour sales adjustment; adjustments for cost changes that are not within SCE's control; a cost of capital trigger mechanism based on changes in a bond index; standards for service reliability and safety; and a net revenue-sharing mechanism that determines how customers and shareholders will share gains and losses from T&D operations. In July 1996, SCE filed a PBR proposal for its hydroelectric plants and a proposed structure for performance-based local reliability contracts for certain fossil-fueled plants. If approved, the hydro PBR would be in effect for three years and the initial terms of the local reliability contracts, which are subject to FERC approval, would be in effect for up to three years, both beginning January 1, 1998. A final CPUC decision on hydro PBR is expected by year-end 1997.

In July 1996, SCE filed a proposal with the CPUC related to the conceptual aspects of separating the costs associated with generation, transmission, distribution, public benefit programs and the CTC. The filing was in response to CPUC and FERC directives which require electric services, such as T&D, to be functionally separate and available to all customers on a nondiscriminatory basis without cost-shifting among customers. On December 6, 1996, SCE filed a more comprehensive plan for the functional unbundling of SCE's rates for electric service, beginning on January 1, 1998. In response to CPUC and FERC orders, as well as the new restructuring legislation, this filing addressed the implementation-level detail for the functional unbundling of rates in separate charges for energy, transmission, distribution, the CTC, public benefit programs and nuclear decommissioning. The filing also included proposals for establishing new regulatory proceedings to replace current proceedings that will no longer be necessary during the rate freeze period.

Although depreciation-related differences could result from applying a regulatory prescribed depreciation method (straight-line, remaining-life method) rather than a method that would have been applied absent the regulatory process, SCE believes that the depreciable lives of its generation-related assets would not vary significantly from that of an unregulated enterprise, as the CPUC bases depreciable lives on periodic studies that reflect the physical useful lives of the assets. SCE also believes that any depreciation-related differences would be recovered through the CTC.

If events occur during the restructuring process that result in all or a portion of the CTC being improbable of recovery, SCE could have additional write-offs associated with these costs if they are not recovered through another regulatory mechanism. At this time, SCE cannot predict what other revisions will ultimately be made during the restructuring process in subsequent proceedings or implementation phases, or the effect, after the transition period, that competition will have on its results of operations or financial position.

Subsequent Event

If the CPUC's restructuring is implemented as outlined, SCE would be allowed to recover its CTC (subject to a lower return on equity) and believes it should be allowed to continue to apply accounting standards that recognize the economic effects of rate regulation for its generation-related assets during the 1998-2001 transition period. However, in response to a request by the staff of the Securities and Exchange Commission (SEC), in December 1996, SCE submitted its views on the continued applicability of regulatory accounting standards for its generation-related assets. In its submittal, SCE and its independent accountants jointly concluded that, based on their current analysis, SCE will continue to meet the criteria for applying these accounting standards through the 1998-2001 transition period. In its February 1997 response, the SEC staff expressed continuing concern with SCE's conclusion and indicated that they wanted to meet further with SCE and the other major California electric utilities to resolve this matter. SCE and its independent accountants continue to believe that SCE meets such criteria and plan to meet with the SEC staff to present additional and clarifying information seeking to convince the SEC staff of the merits of SCE's position. The authority to require SCE to discontinue applying regulatory accounting standards rests with the SEC. If SCE is required to discontinue the application of these accounting standards for its generation-related assets, it would have to write off generation-related regulatory assets, which at December 31, 1996, totaled approximately $600 million on an after-tax basis, primarily for the recovery of income tax benefits previously flowed-through to customers, the Palo Verde phase-in plan and unamortized loss on reacquired debt.

SCE believes that a proper application of regulatory accounting standards will result in it no longer meeting the criteria to apply these accounting standards to all of its non-hydroelectric generation-related assets after the end of the 1998-2001 transition period. If SCE continues the application of these accounting standards during the transition period, but during the transition period events occur that result in SCE no longer meeting the criteria for applying such standards, SCE may be required to write off the remaining balance of its recorded generation-related regulatory assets existing at that time.

If a non-cash write-off is required, SCE believes that it should not affect the stranded-cost recovery plans set forth in the CPUC's December 1995 restructuring decision and legislation enacted by the State of California in September 1996.

FERC Stranded Cost/Open Access Transmission Decision

In April 1996, the FERC issued its decision on stranded cost recovery and open access transmission, effective July 1996. The decision requires all electric utilities subject to the FERC's jurisdiction to file transmission tariffs which provide competitors with increased access to transmission facilities for wholesale transactions and also establishes information requirements for the transmission utility. The decision also provides utilities with the recovery of stranded costs, which are prior-service costs incurred under the current regulatory framework. In addition to providing recovery of stranded costs associated with existing wholesale customers, the FERC directed that it would have primary jurisdiction over the recovery of stranded costs associated with retail-turned-wholesale customers, such as the formation of a new municipal electric system. Retail stranded costs resulting from a state-authorized retail direct-access program are the responsibility of the states and the FERC would only address recovery of these costs if the state has no authority to do so. In compliance with the April 1996 FERC decision, SCE filed a revised open access tariff with the FERC in July 1996. The tariff became effective on an interim basis, subject to refund, as of its filing date. Several wholesale customers have filed protests with the FERC on the transmission rate levels, and a ruling from the FERC setting the rates to be decided at formal hearings is anticipated in early 1997.

Mohave Generating Station

A 1994 CPUC decision stated that SCE was liable for expenditures related to a 1985 accident at the Mohave Generating Station. In July 1996, the CPUC approved a settlement agreement between SCE and the ORA which resulted in a $39 million (including interest) refund to SCE's customers. The refund, which had been previously reserved, was completed by year-end 1996.

Canadian Gas Contracts

In May 1994, SCE filed its testimony in the non-Qualifying Facilities phase of the 1994 Energy Cost Adjustment Clause proceeding. In May 1995, the ORA filed its report on the reasonableness of SCE's gas supply costs for both the 1993 and 1994 record periods. The report recommends a disallowance of $13.3 million for excessive costs incurred from November 1993 through March 1994 associated with SCE's Canadian gas purchase and supply contracts. The report requests that the CPUC defer finding SCE's Canadian supply and transportation agreements reasonable for the duration of their terms and that the costs under these contracts be reviewed on a yearly basis. In October 1996, the ORA issued its report for the 1995 record period recommending a $37.6 million disallowance for excessive costs incurred from April 1994 through March 1995. Both proposed disallowances have been consolidated into one proceeding. SCE and the ORA have filed several rounds of testimony on this issue. Hearings began in January 1997 and are expected to conclude in February 1997. A decision is expected in late 1997.

Palo Verde Rate-making Mechanism

On December 23, 1996, the CPUC issued a final decision on SCE's proposal for a new rate mechanism for its 15.8% share of the three units at Palo Verde. The decision adopts the Palo Verde All-Party Settlement filed with the CPUC on November 15, 1996. The settlement was based on a Memorandum of Understanding signed by all of the active parties to the Palo Verde proceeding. Under the settlement, SCE has the opportunity to recover its remaining investment (approximately $1.2 billion) in Palo Verde beginning January 1, 1997, and ending December 31, 2001, earning a reduced rate of return on rate base of 7.35% instead of the current 9.49%. Also, SCE will utilize a balancing account to pass through Palo Verde's incremental operating costs (considered reasonable as long as they do not exceed 30% of a baseline forecast and the site's gross annual capacity factor does not go below 55%) to ratepayers. Beginning January 1, 1998, this balancing account will become part of the CTC mechanism. If SCE's actual costs are less than the forecast, the difference will benefit ratepayers as a credit to the CTC mechanism. The existing nuclear unit incentive procedure will continue only for purposes of calculating a reward for performance of any unit above an 80% capacity factor for a fuel cycle. After 2001, SCE's ratepayers will receive 50% of the benefits derived from the operation of Palo Verde.

Note 3. Financial Instruments

Long-Term Debt

California law prohibits SCE from incurring or guaranteeing debt for its nonutility affiliates.

Almost all SCE properties are subject to a trust indenture lien.

SCE has pledged first and refunding mortgage bonds as security for borrowed funds obtained from pollution-control bonds issued by government agencies. SCE uses these proceeds to finance construction of pollution-control facilities. Bondholders have limited discretion in redeeming certain pollution-control bonds, and SCE has arranged with securities dealers to remarket or purchase them if necessary.

Long-term debt maturities and sinking-fund requirements for the next five years are: 1997—$501 million; 1998—$447 million; 1999—$155 million; 2000—$325 million; and 2001—$400 million.

Long-term debt consisted of:

In millions December 31,	1996	1995
First and refunding mortgage bonds:		
1997—2000 (5.45% to 7.5%)	$ 1,025	$ 1,025
2001—2005 (5.625% to 6.25%)	450	450
2017—2026 (6.9% to 8.875%)	1,250	1,637
Pollution-control bonds:		
1999—2027 (5.4% to 7.2% and variable)	1,204	1,205
Funds held by trustees	(2)	(2)
Debentures and notes:		
1998—2006 (5.6% to 8.25%)	1,195	795
Subordinated debentures:		
2044 (8.375%)	100	100
Commercial paper for nuclear fuel	112	70
Long-term debt due within one year	(501)	(1)
Unamortized debt discount—net	(54)	(64)
Total	$ 4,779	$ 5,215

Short-Term Debt

SCE has lines of credit it can use at negotiated or bank index rates. At December 31, 1996, available lines totaled $1.1 billion, with $600 million for short-term debt and $500 million available for the long-term refinancing of certain variable-rate pollution-control debt.

Short-term debt consisted of commercial paper used to finance fuel inventories, balancing account undercollections and general cash requirements. Commercial paper outstanding at December 31, 1996, and 1995, was $345 million and $433 million, respectively. Commercial paper intended to finance nuclear fuel scheduled to be used more than one year after the balance sheet date is classified as long-term debt in connection with refinancing terms under five-year term lines of credit with commercial banks. Weighted-average interest rates were 5.5% and 5.8%, at December 31, 1996, and 1995, respectively.

Other Financial Instruments

SCE's risk management policy allows the use of derivative financial instruments to manage financial exposure on its investments and fluctuations in interest rates, but prohibits the use of these instruments for speculative or trading purposes.

Interest rate swaps and caps are used to reduce the potential impact of interest rate fluctuations on floating rate long-term debt. The interest rate swap agreement requires the parties to pledge collateral according to bond rating and market interest rate changes. At December 31, 1996, SCE had pledged $16 million as collateral due to a decline in market interest rates. SCE is exposed to credit loss in the event of nonperformance by counterparties to these agreements, but does not expect the counterparties to fail to meet their obligations.

For both balance sheet dates presented, SCE had the following derivative financial instruments:

Category	Contract Amount/Terms	Purpose
Interest rate swap	$196 million due 2008	fix interest rate exposure at 5.585%
Interest rate cap	$30 million expires 1997 debt due 2027	fix interest rate exposure at 6% over variable term of the debt

Fair values of financial instruments were:

Instrument	December 31, In millions	1996 Cost Basis	1996 Fair Value	1995 Cost Basis	1995 Fair Value
Financial assets:					
Decommissioning trusts		$1,217	$1,485	$1,069	$1,260
Equity investments		11	68	9	41
Financial liabilities:					
DOE decommissioning and decontamination fees		54	45	58	49
Interest rate swap and cap		—	16	—	18
Long-term debt		4,779	5,001	5,215	5,487
Preferred stock subject to mandatory redemption		275	286	275	288

Financial assets are carried at their fair value, which is based on quoted market prices. Financial liabilities are recorded at cost. Financial liabilities' fair values are based on: termination costs for the interest rate swap; brokers' quotes for long-term debt, preferred stock and the cap; and discounted future cash flows for U.S. Department of Energy (DOE) decommissioning and decontamination fees. Due to their short maturities, amounts reported for cash equivalents and short-term debt approximate fair value.

Gross unrealized holding gains on financial assets were:

In millions December 31,	1996	1995
Decommissioning trusts:		
Municipal bonds	$ 79	$ 52
Stocks	138	122
U.S. government issues	39	11
Short-term and other	12	6
	268	191
Equity investments	57	32
Total	$325	$223

There were no unrealized holding losses on financial assets for the years presented.

Note 4. Equity

The CPUC regulates SCE's capital structure, limiting the dividends it may pay Edison International. At December 31, 1996, SCE had the capacity to pay $112 million in additional dividends and continue to maintain its authorized capital structure.

Authorized common stock is 560 million shares with no par value. Authorized shares of preferred and preference stock are: $25 cumulative preferred--24 million; $100 cumulative preferred--12 million; and preference--50 million. All cumulative preferred stocks are redeemable. Mandatorily redeemable preferred stocks are subject to sinking-fund provisions. When preferred shares are redeemed, the premiums paid are charged to common equity. There are no preferred stock redemption requirements for the next five years.

Cumulative preferred stock consisted of:

Dollars in millions, except per-share amounts	December 31, 1996 Shares Outstanding	December 31, 1996 Redemption Price	1996	1995
Not subject to mandatory redemption:				
$25 par value:				
4.08% Series	1,000,000	$ 25.50	$ 25	$ 25
4.24	1,200,000	25.80	30	30
4.32	1,653,429	28.75	41	41
4.78	1,296,769	25.80	33	33
5.80	2,200,000	25.25	55	55
7.36	4,000,000	25.00	100	100
Total			$284	$284
Subject to mandatory redemption:				
$100 par value preferred stock:				
6.05% Series	750,000	$100.00	$ 75	$ 75
6.45	1,000,000	100.00	100	100
7.23	1,000,000	100.00	100	100
Total			$275	$275

In 1995, 750,000 shares of Series 7.58% preferred stock were redeemed. There were no other preferred stock issuances or redemptions for the years presented.

Note 5. Income Taxes

SCE and its subsidiaries will be included in Edison International's consolidated federal income tax and combined state franchise tax returns. Under income tax allocation agreements, each subsidiary calculates its own tax liability.

Income tax expense includes the current tax liability from operations and the change in deferred income taxes during the year. Investment tax credits are amortized over the lives of the related properties.

The components of the net accumulated deferred income tax liability were:

In millions December 31,	1996	1995
Deferred tax assets:		
Property-related	$ 247	$ 276
Investment tax credits	206	222
Regulatory balancing accounts	205	166
Decommissioning-related	208	73
Other	429	601
Total	$ 1,295	$ 1,338
Deferred tax liabilities:		
Property-related	$ 3,550	$ 3,670
Other	675	514
Total	$ 4,225	$ 4,184
Accumulated deferred income taxes—net	$ 2,930	$ 2,846
Classification of accumulated deferred income taxes:		
Included in deferred credits	$ 3,170	$ 3,323
Included in current assets	240	477

The current and deferred components of income tax expense were:

In millions Year ended December 31,	1996	1995	1994
Current:			
Federal	$386	$560	$431
State	129	165	123
	515	725	554
Deferred—federal and state:			
Accrued charges	(14)	1	(25)
Depreciation	(14)	21	46
Investment and energy tax credits—net	(24)	(25)	(22)
Pension reserves	45	(3)	(8)
Rate phase-in plan	(32)	(46)	(51)
Regulatory balancing accounts	34	(118)	(7)
State tax privilege year	21	(12)	(14)
Other	(20)	(33)	(21)
	(4)	(215)	(102)
Total income tax expense	$511	$510	$452
Classification of income taxes:			
Included in operating income	$578	$560	$508
Included in other income	(67)	(50)	(56)

The composite federal and state statutory income tax rate was 41.045% for all years presented.

The federal statutory income tax rate is reconciled to the effective tax rate below:

Year ended December 31,	1996	1995	1994
Federal statutory rate	35.0%	35.0%	35.0%
Capitalized software	(0.8)	(0.8)	(2.1)
Depreciation and other	4.5	4.3	4.9
Investment and energy tax credits	(2.0)	(2.2)	(2.0)
State tax—net of federal deduction	7.1	6.5	5.7
Effective tax rate	43.8%	42.8%	41.5%

Note 6. Employee Benefit Plans

Stock Option Plans

Under its Long-Term Incentive Compensation Plan, SCE participates in the use of 8.2 million shares of parent company common stock reserved for potential issuance under various stock compensation programs to directors, officers and senior managers of Edison International and its affiliates. Under these programs, there are currently outstanding to officers and senior managers of SCE, options on 2.9 million shares of Edison International common stock.

Each option may be exercised to purchase one share of Edison International common stock, and is exercisable at a price equivalent to the fair market value of the underlying stock at the date of grant. Edison International stock options include a dividend equivalent feature. Generally, for options issued before 1994, amounts equal to dividends accrue on the options at the same time and at the same rate as would be payable on the number of shares of Edison International common stock covered by the options. The amounts accumulate without interest. The optionee has no right to payment of these dividend equivalents until the underlying stock options are exercised. For Edison International stock options issued subsequent to 1993, dividend equivalents are subject to reduction unless certain shareholder return performance criteria are met.

Edison International stock options have a 10-year term with one-third of the total award vesting after each of the first three years of the award term. The options are not transferable, except by will or domestic relations order. If an optionee retires, dies or is permanently and totally disabled during the three-year vesting period, the unvested options will vest and be exercisable to the extent of 1/36 of the grant for each full month of service during the vesting period. Unvested options of any person who has served in the past on the Edison International or SCE Management Committee will vest and be exercisable upon the member's retirement, death or permanent and total disability. Upon retirement, death or permanent and total disability, the vested options may continue to be exercised within their original terms by the recipient or beneficiary. If an optionee is terminated other than by retirement, death or permanent and total disability, options which had vested as of the prior anniversary date of the grant are forfeited unless exercised within 180 days of the date of termination. All unvested options are forfeited on the date of termination.

Compensation expense recorded under the stock-compensation program was $8 million, $4 million and $(2) million for 1996, 1995 and 1994, respectively. A decline during 1994 in the market value of the underlying shares optioned resulted in the recapture of previously recognized expense.

Stock-based compensation expense under the fair-value method of accounting would have resulted in pro forma net income of approximately $653 million in 1996 and $677 million in 1995.

The weighted-average fair value of options granted during 1996 and 1995, was $6.27 per share option and $6.92 per share option, respectively. The weighted-average remaining life of options outstanding, as of December 31, 1996, and 1995, was 7 years and 8 years, respectively.

The fair value for each option granted during 1996 and 1995, reflecting the basis for the above pro forma disclosures, was determined on the date of grant using the Black-Scholes option-pricing model. The following assumptions were used in determining fair value through the model:

	1996	1995
Expected life	7 years	8 years
Risk-free interest rate	5.5%	7.9%
Expected volatility	17%	17%

The recognition of dividend equivalents results in no dividends assumed for purposes of fair-value determination. The application of fair-value accounting in arriving at the pro forma disclosures above is not an indication of future income statement effects. The pro forma disclosures do not reflect the effect of fair-value accounting on stock-based compensation awards granted prior to 1995.

Pension Plan

SCE has a noncontributory, defined-benefit pension plan that covers employees meeting minimum service requirements. Benefits are based on years of accredited service and average base pay. SCE funds the plan on a level-premium actuarial method. These funds are accumulated in an independent trust. Annual contributions meet minimum legal funding requirements and do not exceed the maximum amounts deductible for income taxes. Prior service costs from pension plan amendments are funded over 30 years. Plan assets are primarily common stocks, corporate and government bonds, and short-term investments. In 1996, SCE recorded pension gains from a special voluntary early retirement program.

The plan's funded status was:

In millions December 31,	1996	1995
Actuarial present value of benefit obligations:		
Vested benefits	$1,670	$1,696
Nonvested benefits	71	210
Accumulated benefit obligation	1,741	1,906
Value of projected future compensation levels	261	479
Projected benefit obligation	$2,002	$2,385
Fair value of plan assets	$2,165	$2,620
Projected benefit obligation less than plan assets	$ (163)	$ (235)
Unrecognized net gain	300	326
Unrecognized prior service cost	(199)	(6)
Unrecognized net obligation (17-year amortization)	(43)	(49)
Pension liability (asset)	$ (105)	$ 36
Discount rate	7.75%	7.25%
Rate of increase in future compensation	5.0%	5.0%
Expected long-term rate of return on assets	8.0%	8.0%

SCE recognizes pension expense calculated under the actuarial method used for ratemaking.

The components of pension expense were:

In millions Year ended December 31,	1996	1995	1994
Service cost for benefits earned	$ 49	$ 57	$ 67
Interest cost on projected benefit obligation	178	156	148
Actual return on plan assets	(343)	(454)	(28)
Net amortization and deferral	145	268	(140)
Pension expense under accounting standards	29	27	47
Special termination benefits	—	3	15
Regulatory adjustment—deferred	22	22	1
Net pension expense recognized	51	52	63
Settlement gain	(121)	—	—
Total expense (gain)	$ (70)	$ 52	$ 63

Postretirement Benefits Other Than Pensions

Employees retiring at or after age 55 with at least 10 years of service (or those eligible under the 1996 special voluntary early retirement program), are eligible for postretirement health and dental care, life insurance and other benefits. Health and dental care benefits are subject to deductibles, copayment provisions and other limitations.

SCE is amortizing its obligation related to prior service over 20 years. SCE funds these benefits (by contributions to independent trusts) up to tax-deductible limits, in accordance with rate-making practices. In 1996, SCE recorded special termination expenses due to a special voluntary early retirement program. Any difference between recognized expense and amounts authorized for rate recovery is not expected to be material (except for the impact of the early retirement program) and will be charged to earnings.

Trust assets are primarily common stocks, corporate and government bonds, and short-term investments.

The funded status of these benefits is reconciled to the recorded liability below:

In millions December 31,	1996	1995
Actuarial present value of benefit obligation:		
Retirees	$ 928	$ 402
Employees eligible to retire	35	103
Other employees	386	556
Accumulated benefit obligation	$1,349	$1,061
Fair value of plan assets	$ 617	$ 400
Plan assets less than accumulated benefit obligation	$ 732	$ 661
Unrecognized transition obligation	(430)	(457)
Unrecognized net gain (loss)	(231)	(203)
Recorded liability	$ 71	$ 1
Discount rate	7.75%	7.5%
Expected long-term rate of return on assets	8.5%	8.5%

The components of postretirement benefits other than pensions expense were:

In millions Year ended December 31,	1996	1995	1994
Service cost for benefits earned	$ 31	$ 35	$ 29
Interest cost on benefit obligation	90	77	72
Actual return on plan assets	(43)	(28)	(20)
Amortization of loss	6	1	–
Amortization of transition obligation	27	27	36
Net expense	111	112	117
Amortization of prior funding	–	–	2
Special termination expense	72	–	–
Total expense	$ 183	$ 112	$ 119

The assumed rate of future increases in the per-capita cost of health care benefits is 8.25% for 1997, gradually decreasing to 5% for 2004 and beyond. Increasing the health care cost trend rate by one percentage point would increase the accumulated obligation as of December 31, 1996, by $206 million annual aggregate service and interest costs by $24 million.

Employee Savings Plan

SCE has a 401(k) defined contribution savings plan designed to supplement employees' retirement income. The plan received employer contributions of $24 million in 1996, $19 million in 1995 and $21 million in 1994.

Notes to Consolidated Financial Statements

Note 7. Jointly Owned Utility Projects

SCE owns interests in several generating stations and transmission systems for which each participant provides its own financing. SCE's share of expenses for each project is included in the consolidated statements of income.

The investment in each project, as included in the consolidated balance sheet as of December 31, 1996, was:

In millions	Plant in Service	Accumulated Depreciation	Under Construction	Ownership Interest
Transmission systems:				
Eldorado	$ 29	$ 8	$ 2	60%
Pacific Intertie	227	72	12	50
Generating stations:				
Four Corners Units 4 and 5 (coal)	458	236	2	48
Mohave (coal)	300	142	8	56
Palo Verde (nuclear)	1,596	425	6	16
San Onofre (nuclear)	4,186	1,836	28	75
Total	$6,796	$2,719	$ 58	

Note 8. Leases

SCE has operating leases, primarily for vehicles, with varying terms, provisions and expiration dates.

Estimated remaining commitments for noncancelable leases at December 31, 1996, were:

Year ended December 31,	In millions
1997	$18
1998	15
1999	11
2000	9
2001	5
Thereafter	7
Total	$65

Note 9. Commitments

Nuclear Decommissioning

SCE plans to decommission its nuclear generating facilities at the end of each facility's operating license by a prompt removal method authorized by the Nuclear Regulatory Commission. Decommissioning is estimated to cost $2.0 billion in current-year dollars, based on site-specific studies performed in 1993 for San Onofre and 1992 for Palo Verde. Changes in the estimated costs, timing of decommissioning, or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission in the near term. Decommissioning is scheduled to begin in 2013 at San Onofre and 2024 at Palo Verde. San Onofre Unit 1, which shut down in 1992, is expected to be secured until decommissioning begins at the other San Onofre units.

Decommissioning costs, which are recovered through customer rates, are recorded as a component of depreciation expense. Decommissioning expense was $148 million in 1996, $151 million in 1995 and $122 million in 1994. The accumulated provision for decommissioning was $949 million at December 31, 1996, and $823 million at December 31, 1995. The estimated costs to decommission San Onofre Unit 1 ($263 million) are recorded as a liability.

Decommissioning funds collected in rates are placed in independent trusts, which, together with accumulated earnings, will be utilized solely for decommissioning.

Trust investments include:

In millions	Maturity Dates	December 31, 1996	December 31, 1995
Municipal bonds	1999-2021	$ 400	$ 348
Stocks	-	549	390
U.S. government issues	1998-2024	212	145
Short-term and other	1996-2024	56	186
Trust fund balance (at cost)		$1,217	$1,069

Trust fund earnings (based on specific identification) increase the trust fund balance and the accumulated provision for decommissioning. Net earnings were $49 million in 1996, $51 million in 1995 and $26 million in 1994. Proceeds from the sales of securities (which are reinvested) were $1.0 billion in both 1996 and 1995, and $1.1 billion in 1994. Approximately 89% of the trust fund contributions were tax-deductible.

The Financial Accounting Standards Board has issued an exposure draft related to accounting practices for removal costs, including decommissioning of nuclear power plants. The exposure draft would require SCE to report its estimated decommissioning costs as a liability, rather than recognizing these costs over the term of each facility's operating license (current industry practice). SCE does not believe that the changes proposed in the exposure draft would have an adverse effect on its results of operations even after deregulation due to its current and expected future ability to recover these costs through customer rates.

Other Commitments

SCE has fuel supply contracts which require payment only if the fuel is made available for purchase.

SCE has power-purchase contracts with certain qualifying facilities (cogenerators and small power producers) and other utilities. The qualifying facility contracts provide for capacity payments if a facility meets certain performance obligations and energy payments based on actual power supplied to SCE. There are no requirements to make debt-service payments.

SCE has unconditional purchase obligations for part of a power plant's generating output, as well as firm transmission service from another utility. Minimum payments are based, in part, on the debt-service requirements of the provider, whether or not the plant or transmission line is operable. The purchased-power contract is not expected to provide more than 5% of current or estimated future operating capacity. SCE's minimum commitment under both contracts is approximately $205 million through 2017.

Certain commitments for the years 1997 through 2001 are estimated below:

In millions	1997	1998	1999	2000	2001
Projected construction expenditures	$ 802	$ 636	$ 664	$ 647	$ 650
Fuel supply contracts	269	231	221	240	234
Purchased-power capacity payments	696	699	701	702	695
Unconditional purchase obligations	9	10	10	10	10

Note 10. Contingencies

In addition to the matters disclosed in these notes, SCE is involved in legal, tax and regulatory proceedings before various courts and governmental agencies regarding matters arising in the ordinary course of business. SCE believes the outcome of these proceedings will not materially affect its results of operations or liquidity.

Environmental Protection

SCE is subject to numerous environmental laws and regulations, which require it to incur substantial costs to operate existing facilities, construct and operate new facilities, and mitigate or remove the effect of past operations on the environment.

SCE records its environmental liabilities when site assessments and/or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. SCE reviews its sites and measures the liability quarterly, by assessing a range of reasonably likely costs for each identified site using currently available information, including existing technology, presently enacted laws and regulations, experience gained at similar sites, and the probable level of involvement and financial condition of other potentially responsible parties. These estimates include costs for site investigations, remediation, operations and maintenance, monitoring and site closure. Unless there is a probable amount, SCE records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts). While SCE has numerous insurance policies that it believes may provide coverage for some of these liabilities, it does not recognize recoveries in its financial statements until they are realized.

SCE's recorded estimated minimum liability to remediate its 55 identified sites was $114 million at December 31, 1996. The ultimate costs to clean up SCE's identified sites may vary from its recorded liability due to numerous uncertainties inherent in the estimation process, such as: the extent and nature of contamination; the scarcity of reliable data for identified sites; the varying costs of alternative cleanup methods; developments resulting from investigatory studies; the possibility of identifying additional sites; and the time periods over which site remediation is expected to occur. SCE believes that, due to these uncertainties, it is reasonably possible that cleanup costs could exceed its recorded liability by up to $211 million. The upper limit of this range of costs was estimated using assumptions least favorable to SCE among a range of reasonably possible outcomes.

The CPUC allows SCE to recover environmental-cleanup costs at 35 of its sites, representing $101 million of its recorded liability, through an incentive mechanism. SCE may request to include additional sites. Under this mechanism, SCE will recover 90% of cleanup costs through customer rates; shareholders fund the remaining 10%, with the opportunity to recover these costs from insurance carriers and other third parties. SCE has successfully settled insurance claims with a number of its carriers. Costs incurred at the remaining 20 sites are expected to be recovered through customer rates. SCE has recorded a regulatory asset of $104 million for its estimated minimum environmental-cleanup costs expected to be recovered through customer rates.

SCE's identified sites include several sites for which there is a lack of currently available information, including the nature and magnitude of contamination, and the extent, if any, that SCE may be held responsible for contributing to any costs incurred for remediating these sites. Thus, no reasonable estimate of cleanup costs can be made for these sites.

SCE expects to clean up its identified sites over a period of up to 30 years. Remediation costs in each of the next several years are expected to range from $4 million to $8 million. Recorded costs for 1996 were $7 million.

Based on currently available information, SCE believes it is unlikely that it will incur amounts in excess of the upper limit of the estimated range and, based upon the CPUC's regulatory treatment of environmental-cleanup costs, SCE believes that costs ultimately recorded will not have a material adverse effect on its results of operations or financial position. There can be no assurance, however, that future developments, including additional information about existing sites or the identification of new sites, will not require material revisions to such estimates.

Nuclear Insurance

Federal law limits public liability claims from a nuclear incident to $8.9 billion. SCE and other owners of San Onofre and Palo Verde have purchased the maximum private primary insurance available ($200 million). The balance is covered by the industry's retrospective rating plan that uses deferred premium charges to every reactor licensee if a nuclear incident at any licensed reactor in the U.S. results in claims and/or costs which exceed the primary insurance at that plant site. Federal regulations require this secondary level of financial protection. The Nuclear Regulatory Commission exempted San Onofre Unit 1 from this secondary level, effective June 1994. The maximum deferred premium for each nuclear incident is $79 million per reactor, but not more than $10 million per reactor may be charged in any one year for each incident. Based on its ownership interests, SCE could be required to pay a maximum of $158 million per nuclear incident. However, it would have to pay no more than $20 million per incident in any one year. Such amounts include a 5% surcharge if additional funds are needed to satisfy public liability claims and are subject to adjustment for inflation. If the public liability limit above is insufficient, federal regulations may impose further revenue-raising measures to pay claims, including a possible additional assessment on all licensed reactor operators.

Property damage insurance covers losses up to $500 million, including decontamination costs, at San Onofre and Palo Verde. Decontamination liability and property damage coverage exceeding the primary $500 million has also been purchased in amounts greater than federal requirements. Additional insurance covers part of replacement power expenses during an accident-related nuclear unit outage. These policies are issued primarily by mutual insurance companies owned by utilities with nuclear facilities. If losses at any nuclear facility covered by the arrangement were to exceed the accumulated funds for these insurance programs, SCE could be assessed retrospective premium adjustments of up to $34 million per year. Insurance premiums are charged to operating expense.

Quarterly Financial Data

	1996					1995				
In millions	Total	Fourth	Third	Second	First	Total	Fourth	Third	Second	First
Operating revenue	$7,583	$1,866	$2,346	$1,611	$1,760	$7,873	$1,903	$2,510	$1,738	$1,722
Operating income	1,133	231	382	257	263	1,149	246	369	261	273
Net income	655	121	256	131	147	680	130	251	150	149
Earnings available for common stock	621	113	247	123	138	643	121	243	140	139
Common dividends declared	735	196	178	180	181	546	136	136	137	137

Responsibility for Financial Reporting

The management of Southern California Edison Company (SCE) is responsible for the integrity and objectivity of the accompanying financial statements. The statements have been prepared in accordance with generally accepted accounting principles applied on a consistent basis and are based, in part, on management estimates and judgment.

SCE maintains systems of internal control to provide reasonable, but not absolute, assurance that assets are safeguarded, transactions are executed in accordance with management's authorization and the accounting records may be relied upon for the preparation of the financial statements. There are limits inherent in all systems of internal control, the design of which involves management's judgment and the recognition that the costs of such systems should not exceed the benefits to be derived. SCE believes its systems of internal control achieve this appropriate balance. These systems are augmented by internal audit programs through which the adequacy and effectiveness of internal controls and policies and procedures are monitored, evaluated and reported to management. Actions are taken to correct deficiencies as they are identified.

SCE's independent public accountants, Arthur Andersen LLP, are engaged to audit the financial statements in accordance with generally accepted auditing standards and to express an informed opinion on the fairness, in all material respects, of SCE's reported results of operations, cash flows and financial position.

As a further measure to assure the ongoing objectivity of financial information, the audit committee of the board of directors, which is composed of outside directors, meets periodically, both jointly and separately, with management, the independent public accountants and internal auditors, who have unrestricted access to the committee. The committee recommends annually to the board of directors the appointment of a firm of independent public accountants to conduct audits of its financial statements; considers the independence of such firm and the overall adequacy of the audit scope and SCE's systems of internal control; reviews financial reporting issues; and is advised of management's actions regarding financial reporting and internal control matters.

SCE maintains high standards in selecting, training and developing personnel to assure that its operations are conducted in conformity with applicable laws and is committed to maintaining the highest standards of personal and corporate conduct. Management maintains programs to encourage and assess compliance with these standards.

R K Bushey

Richard K. Bushey
Vice President
and Controller

John E. Bryson

John E. Bryson
Chairman of the Board
and Chief Executive Officer

January 31, 1997

Report of Independent Public Accountants

To the Shareholders and the Board of Directors,
Southern California Edison Company:

We have audited the accompanying consolidated balance sheets of Southern California Edison Company (SCE, a California corporation) and its subsidiaries as of December 31, 1996, and 1995, and the related consolidated statements of income, retained earnings and cash flows for each of the three years in the period ended December 31, 1996. These financial statements are the responsibility of SCE's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 SCE and its subsidiaries as of December 31, 1996, and 1995, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 1996, in conformity with generally accepted accounting principles.

Arthur Andersen LLP

ARTHUR ANDERSEN LLP

Los Angeles, California
January 31, 1997 (except with respect to the "Subsequent Event" discussed under "Electric Utility Industry Restructuring" in Note 2, as to which the date is February 21, 1997).

Board of Directors

John E. Bryson
Chairman of the Board and CEO, Edison International and SCE

Howard P. Allen
Chairman of the Executive Committee, Edison International and SCE

Winston H. Chen
Chairman of the Paramitas Foundation and Chairman of Paramitas Investment Corporation, Santa Clara, California

Stephen E. Frank
President and Chief Operating Officer, SCE

Camilla C. Frost
Trustee, Chandler Trusts and Director and Secretary-Treasurer, Chandis Securities Company, Los Angeles, California

Joan C. Hanley
General Partner, Miramonte Vineyards, Rancho Palos Verdes, California

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General Partner, DAE Limited Partnership Ltd., Ojai, California

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Chairman of the Board and CEO, Avery Dennison Corporation, Pasadena, California

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Admiral USN, Retired, President, Joint Oceanographic Institutions, Inc. and President, Consortium for Oceanographic Research and Education, Washington, D.C.

Edward Zapanta, M.D.
Physician and Neurosurgeon, South Pasadena, California

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Chairman of the Board and CEO

Stephen E. Frank
President and Chief Operating Officer

Bryant C. Danner
Executive Vice President and General Counsel

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Executive Vice President and Chief Financial Officer

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Vice President, Labor Relations

Dwight E. Nunn
Vice President, Nuclear Engineering and Technical Services

Frank J. Quevedo
Vice President, Equal Opportunity

Richard M. Rosenblum
Vice President, Distribution Business Unit

Beverly P. Ryder
Corporate Secretary and Special Assistant to the Chairman/CEO

Shareholder Information

Annual Meeting of Shareholders

Thursday, April 17, 1997
10:00 a.m.
The Industry Hills Sheraton Resort and Conference Center
One Industry Hills Parkway
City of Industry, California

Stock Listing and Trading Information

SCE Preferred Stocks

The American and Pacific stock exchanges use the ticker symbol SCE. Previous day's closing prices, when traded, are listed in the daily newspapers in the American Stock Exchange table under the symbol SoCalEd. The 6.05%, 6.45% and 7.23% series are not listed.

Where to Buy and Sell Stock

The listed preferred stocks may be purchased through any brokerage firm. Firms handling unlisted series can be located through your broker.

Transfer Agent and Registrar

Southern California Edison Company maintains shareholder records and is transfer agent and registrar for SCE preferred stock. Shareholders may call Shareholder Services, (800) 347-8625, between 8:00 a.m. and 4:00 p.m. (Pacific time) every business day, regarding:

- stock transfer and name-change requirements;
- address changes, including dividend addresses;
- electronic deposit of dividends;
- taxpayer identification number submission or changes;
- duplicate 1099 forms and W-9 forms;
- notices of and replacement of lost or destroyed stock certificates and dividend checks; and
- requests to eliminate multiple annual report mailings.

The address of Shareholder Services is:

P.O. Box 400, Rosemead, California 91770-0400
FAX: (818) 302-4815

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