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PNM considers this annual report to contain "forward-looking statements" under Federal securities law. It is published to assist shareholders in evaluating PNM and its securities. This report does not contain all of the information material to an evaluation and should be read in conjunction with its periodic reports, proxy statements and other information PNM files with the Securities and Exchange Commission. Please refer to page 39, "Disclosure Regarding Forward-Looking Statements," for a listing of the factors which could cause the Company's actual financial results to differ materially from the prospective information provided by the Company in forward-looking statements.

SELECTED FINANCIAL DATA

(In thousands except per share amounts and ratios)	2000	1999	1998	1997	1996
Total Operating Revenues	$ 1,611,274	$ 1,157,543	$ 1,092,445	$ 1,020,521	$ 873,778
Earnings from Continuing Operations	$ 100,946	$ 79,614	$ 95,119	$ 86,497	$ 72,969
Net Earnings	$ 100,946	$ 83,155	$ 82,682	$ 80,995	$ 72,580
Earnings per Common Share:					
Continuing Operations	$ 2.54	$ 1.93	$ 2.27	$ 2.05	$ 1.73
Basic	$ 2.54	$ 2.01	$ 1.97	$ 1.92	$ 1.72
Diluted	$ 2.53	$ 2.01	$ 1.95	$ 1.91	$ 1.71
Total Assets	$ 2,894,233	$ 2,723,268	$ 2,668,603	$ 2,407,410	$ 2,313,334
Long-Term Debt, including current maturities	$ 953,823	$ 988,489	$ 1,008,614	$ 714,345	$ 728,889
Common Stock Data:					
Market price per common share at year end	$ 26.81	$ 16.25	$ 20.44	$ 23.69	$ 19.63
Book value per common share at year end	$ 23.64	$ 21.79	$ 20.63	$ 19.26	$ 18.06
Average number of common shares outstanding	39,487	41,038	41,774	41,774	41,774
Cash dividend declared per common share	$ 0.80	$ 1.00	$ 0.60	$ 0.68	$ 0.48
Return on Average Common Equity	11.1%	9.5%	9.9%	10.2%	9.8%
Capitalization:					
Common stock equity	48.6%	46.7%	45.4%	52.6%	50.4%
Preferred stock without mandatory redemption requirements	0.7	0.7	0.7	0.8	0.9
Long-term debt, less current maturities	50.7	52.6	53.9	46.6	48.7
	100.0%	100.0%	100.0%	100.0%	100.0%

Due to the discontinuance of the natural gas trading operations of its Energy Services Business Unit in 1998 (see Note 13 to the Consolidated Financial Statements), certain prior year amounts have been reclassified as discontinued operations.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following is management's assessment of Public Service Company of New Mexico ("the Company's") financial condition and the significant factors affecting the results of operations. This discussion should be read in conjunction with the Company's consolidated financial statements and Part I, Item 3. - Legal Proceedings as filed in the Company's 2000 annual report on Form 10-K. Trends and contingencies of a material nature are discussed to the extent known and considered relevant.

The Company is a public utility primarily engaged in the generation, transmission, distribution and sale of electricity and in the transmission, distribution and sale of natural gas within the State of New Mexico. In addition, in pursuing new business opportunities, the Company provides energy and utility related product offerings through its wholly-owned subsidiary, Avistar, Inc. ("Avistar"). As it currently operates, the Company's principal business segments are Utility Operations, which include the Electric Product Offering ("Electric") and the Natural Gas Product Offering ("Gas"), and Generation and Trading Operations ("Generation and Trading"). The Electric Product Offering consists of two major business lines that include distribution and transmission. The transmission business line does not meet the definition of a segment for accounting purposes due to its immateriality, and for purposes of this discussion, it is combined with the distribution product offering.

ELECTRIC

The Company provides jurisdictional retail electric service to a large area of north central New Mexico, including the city of Albuquerque and the city of Santa Fe, and certain other areas of New Mexico. Retail sale revenues, which include distribution and transmission, were $518.7 million, $522.5 million and $536.4 million for the year ended December 31, 2000, 1999 and 1998, respectively, and approximately 369,000, 361,000 and 358,000, respectively, retail electric customers were served by the Company.

The Company owns or leases 2,781 circuit miles of transmission lines, interconnected with other utilities east into Texas, west into Arizona, and north into Colorado and Utah. Due to rapid load growth in recent years, most of the capacity on this transmission system is fully committed and there is no additional access available on a firm commitment basis. These factors, together with significant physical constraints in the system, limit the ability to wheel power into the Company's service area from outside the state.

GAS

The Company's Gas operations distribute natural gas to most of the major communities in New Mexico, including the cities of Albuquerque and Santa Fe, serving approximately 435,000, 426,000 and 419,000 customers as of December 31, 2000, 1999 and 1998, respectively. The Company's gas customer base includes both sales-service customers and transportation-service customers. Sales-service customers purchase natural gas and receive transportation and delivery services from the Company for which the Company receives both cost-of-gas and cost-of-service revenues. Additionally, the Company makes occasional gas sales to off-system customers. Off-system sales deliveries generally occur at interstate pipeline interconnects with the Company's system. Transportation-service customers, who procure gas independently of the Company and contract with the Company for transportation and related services, provide the Company with cost-of-service revenues only.

The Company obtains its supply of natural gas primarily from sources within New Mexico pursuant to contracts with producers and marketers. These contracts are generally sufficient to meet the Company peak-day demand.

The following tables show gas throughput by customer class and gas revenues by customer:

GAS THROUGHPUT

(millions of decatherms)	2000	1999	1998
Residential	28.8	32.1	29.3
Commercial	9.9	10.8	10.1
Industrial	5.0	2.4	1.5
Transportation*	44.9	40.2	36.5
Other	6.4	6.8	8.3
	95.0	92.3	85.7

**Customer-owned gas.*

GAS REVENUES

(thousands of dollars)	2000	1999	1998
Residential	$ 191,221	$ 151,954	$ 160,459
Commercial	52,959	37,300	42,500
Industrial	24,208	8,595	4,876
Transportation*	14,163	12,390	13,464
Other	37,373	26,472	34,676
	$ 319,924	$ 236,711	$ 255,975

The Company's Generation and Trading Operations serve four principal markets. Sales to the Company's Utility Operations to cover jurisdictional electric demand and sales to firm-requirements wholesale customers, sometimes referred to collectively as "system" sales, comprise two of these markets. The third market consists of other contracted sales to third parties for which the Generation and Trading Operations commit to deliver a specified amount of capacity (measured in megawatts-MW) or energy (measured in megawatt hours-MWh) over a given period of time. The fourth market consists of economy energy sales made on an hourly basis at fluctuating, spot-market rates. Sales to the third and fourth markets are sometimes referred to collectively as "off-system" sales. Off-system sales include the Company's energy trading activities.

The following tables show Generation and Trading Operations' sales and revenues by customer class:

GENERATION AND TRADING SALES BY MARKET
(megawatt hours)

	2000	1999	1998
Intersegment sales	7,088,943	6,803,583	6,739,874
Firm-requirements wholesale	193,853	179,249	278,615
Other contracted off-system sales	7,385,266	6,196,499	4,033,931
Economy energy sales	4,773,009	4,795,873	4,469,769
Other	—	—	—
	19,441,071	17,975,204	15,522,189

GENERATION AND TRADING REVENUES BY MARKET
(thousands of dollars)

	2000	1999	1998
Intersegment sales	$ 324,744	$ 318,872	$ 362,722
Firm-requirements wholesale	6,568	7,046	10,708
Other contracted off-system sales	371,900	226,773	142,115
Economy energy sales	369,724	131,549	122,156
Other	2,242	5,741	4,657
	$ 1,075,178	$ 689,981	$ 642,358

The Generation and Trading Operations have ownership interests in certain generating facilities located in New Mexico, including the San Juan Generating Station ("SJGS"), a coal fired unit, and the Four Corners Power Plant ("Four Corners"), a coal fired unit. In addition, the Company has ownership and leasehold interests in Palo Verde Nuclear Generating Station ("PVNGS") located in Arizona. These generation assets are used to supply retail and wholesale customers. The Generation and Trading Operations also own Reeves Generating Station, a gas and oil fired unit and Las Vegas Generating Station, a gas and oil fired unit, that are used solely for reliability purposes or to generate electricity for the wholesale market during peak demand periods in the Generation and Trading Operations' wholesale power markets.

As of December 31, 2000, the total net generation capacity of facilities owned or leased by the Generation and Trading Operations was 1,521 MW. On July 13, 2000, the Company commenced a 20 year power purchase agreement for an additional 132 MW for the rights to all output of a new gas fired generating plant. In addition to its generation capacity, the Generation and Trading Operations purchase power in the open market.

The Company's wholly-owned subsidiary, Avistar, was formed in August 1999 as a New Mexico corporation and is currently engaged in certain unregulated, non-utility businesses, including energy and utility-related services previously operated by the Company. The New Mexico Public Regulation Commission ("PRC"), predecessor of the New Mexico Public Utility Commission ("NMPUC"), authorized the Company to invest $50 million in equity in Avistar and to enter into a reciprocal loan agreement for up to $30 million. The Company has currently invested $35 million in Avistar. In February 2000, Avistar invested $3 million for a 25% ownership interest in AMDAX.com, a start-up company which developed a proprietary auction platform designed to efficiently bring together electricity buyers and sellers in the deregulated natural gas and electricity markets. In the second quarter 2000, Avistar invested $1 million in Nth Power, a venture capital fund. In December 2000, Avistar invested $10 million for a 5% ownership interest in Mainstreet Networks, an Internet Gateway Service Provider. Together with local utilities, Mainstreet Networks plans to provide low-cost Internet-based services to homes through an Internet gateway attached at the customer's electric meter.

On November 9, 2000 the Company and Western Resources, Inc. ("Western Resources") announced that both companies' boards of directors approved an agreement under which the Company will acquire the Western Resources' electric utility operations in a tax-free, stock-for-stock transaction.

The new combined company will serve over one million retail electric customers and 435,000 retail gas customers in New Mexico and Kansas and will have generating capacity of more than 7,000 MW. The transaction exceeds the Company's stated goal of doubling its generation capacity and tripling its power sales more than three years ahead of schedule. The transaction will also make the new company a leading energy supplier in the Western and Midwestern wholesale markets.

The transaction will provide the Company with the opportunity to accelerate its proven growth strategy by developing a similar niche product, asset-backed wholesale power marketing strategy at Western Resources. The Company expects this transaction to contribute significantly towards its targeted 10 percent annual average earnings growth over the next five years.

The strategic nature of the acquisition is based upon revenue-growth. As a result, the Company expects modest cost savings although cost reduction will be one aspect of the integration effort. At present the Company does not intend on significant cost savings associated with involuntary workforce reductions. The new holding company will seek to minimize any workforce effects through reduced hiring, attrition, and other appropriate measures. All existing labor agreements will be honored.

The transaction is expected to close promptly after all of the conditions to its consummation are fulfilled, including the spin off to Western Resources' shareholders of Western Resources' non-utility assets, approval from both companies' shareholders and customary regulatory approvals. (See "Other Issues Facing The Company – Acquisition of Western Resources Electric Operations" below).

Introduction of competitive market forces and restructuring of the electric utility industry in New Mexico continue to be key issues facing the Company. New Mexico's Electric Utility Industry Restructuring Act of 1999 (the "Restructuring Act"), which was enacted into law in April 1999, would begin to open the state's electric power market to customer choice beginning in 2002. The Restructuring Act would give schools, residential and small business customers the opportunity to choose among competing power suppliers beginning in January 2002. Competition would be expanded to include all customers starting in July 2002. Rural electric cooperatives and municipal electric systems have the option not to participate in the competitive market.

Under the Restructuring Act, residential and small business customers who do not select a power supplier in the open market would buy their electricity through their local utility through "standard offer service" whereby the local distribution utility would procure power supplies through a process approved by the PRC. The local distribution utility system and related services such as billing and metering would continue to be regulated by the PRC, while transmission services and wholesale power sales would remain subject to Federal regulation.

The Restructuring Act does not require utilities to divest their generating plants, but requires certain deregulated activities to be separated from activities regulated by the PRC through creation of at least two separate corporations.

The Company plans to reorganize its operations by forming a holding company structure as a means of achieving the corporate and asset separation required by the Restructuring Act. The Company's plan for a holding company structure would separate the Company into two subsidiaries. In June 2000, shareholders approved the mandatory share exchange necessary to implement the holding company structure. If the Company receives all necessary regulatory and other approvals, all of the Company's electric and gas distribution and transmission assets and certain related liabilities would be transferred to a newly created subsidiary ("Asset Transfer"). After this asset transfer, this subsidiary will acquire the name "Public Service Company of New Mexico" (for purposes of this discussion, the subsidiary is referred to as "UtilityCo") and the corporation formerly named Public Service Company of New Mexico will be renamed Manzano Energy Corporation (for purposes of this discussion, the subsidiary is referred to as "PowerCo"). PowerCo would continue to own the Company's existing electric generation and certain other unregulated, competitive assets after completion of the transfer of the regulated business to the newly created utility subsidiary. UtilityCo, PowerCo and Avistar would be wholly-owned subsidiaries of the proposed holding company.

For a discussion on the status of the formation of the holding company and corporate separation, see "Other Issues Facing The Company - The Restructuring Act, The Formation of the Holding Company and Corporate Separation" below.

The restructuring of the electric utility industry is expected to provide new opportunities; however, the Company anticipates that it will experience downward pressure on the Company's utility earnings from their current levels. The reasons for the downward pressure include possible limits on return on equity, disallowance of some stranded costs and the potential loss of certain customers in a competitive environment.

Under the holding company structure proposed to comply with the Restructuring Act, the regulated businesses (natural gas and electric transmission and distribution) will be grouped under a separate company and would focus on the core utility business in New Mexico. The unregulated businesses under the Restructuring Act (power production, bulk power marketing, including energy trading activities and energy services) would aggressively pursue efforts to expand energy marketing and utility related businesses into carefully targeted markets in an effort to increase shareholder value. The Company believes that successful operations of its proposed unregulated business activities under a holding company structure would better position the Company in an increasingly competitive utility environment.

The Company's Generation and Trading Operations have contributed significant earnings to the Company in recent years as a result of increased off-system sales including its energy trading activities. The Company plans to expand its wholesale energy trading functions which could include an expansion of its generation portfolio. The Company continuously evaluates its physical asset acquisition strategies to ensure an optimal mix of base-load generation, peaking generation and purchased power in its power portfolio. In addition to the continued energy trading activities, the Company will further focus on opportunities in the market place where excess capacity is disappearing and mid- to long-term market demands are growing.

The Company's current business plan includes a 300% increase in sales and a doubling of its generating capacity through the construction or acquisition of additional power generation assets in its surrounding region of operations over the next five to seven years. The proposed acquisition of Western Resources electric utility businesses announced on November 9, 2000, will allow the Company to meet this goal well ahead of schedule by adding approximately 5,600 MW to the Company's generation portfolio growth. The Company will continue to pursue growth in its generation portfolio and intends to spend $400 to $800 million over the next five years to achieve generation portfolio growth. Such growth will be dependent upon the Company's ability to generate funds for the Company's expansion. There can be no assurance that these competitive businesses, particularly the generation business, will be successful or, if unsuccessful, that they will not have a direct or indirect adverse effect on the Company.

At the Federal level, there have been a number of proposals on electric restructuring being considered with no concrete timing for definitive actions. None of these proposals have been acted upon by Congress. Issues such as stranded cost recovery, market power, utility regulation reform, the role of states, subsidies, consumer protections and environmental concerns are expected to be reintroduced if not acted upon in the current Congressional session. In addition, the Federal Energy Regulation Commission ("FERC") has stated that if Congress mandates electric retail access, it should leave the details of the program to the states with the FERC having the authority to order the necessary transmission access for the delivery of power for the states' retail access programs.

Although it is unable to predict the ultimate outcome of retail competition in New Mexico, the Company has been and will continue to be active at both the state and Federal levels in the public policy debates on the restructuring of the electric utility industry. The Company will continue to work with customers, regulators, legislators and other interested parties to find solutions that bring benefits from competition while recognizing the importance of reimbursing utilities for past commitments.

The following discussion is based on the financial information presented in Footnote 1 of the Consolidated Financial Statements - Nature of Business and Segment Information. The table below sets forth the operating results as percentages of total operating revenues for each business segment.

YEAR ENDED DECEMBER 31, 2000:

	Utility				Generation and Trading	
	Electric		Gas			
Operating revenues:						
External customers	$ 538,758	99.87%	$ 319,924	100.00%	$ 750,434	69.80%
Intersegment revenues	707	0.13	—	—	324,744	30.20
Total revenues	539,465	100.00	319,924	100.00	1,075,178	100.00
Cost of energy sold	5,048	0.94	195,333	61.06	749,499	69.71
Intersegment purchases	324,744	60.20	—	—	707	0.07
Total fuel costs	329,792	61.13	195,333	61.06	750,206	69.78
Gross margin	209,673	38.87	124,591	38.94	324,972	30.22
Administrative and other costs	43,874	8.13	43,241	13.52	30,009	2.79
Energy production costs	1,208	0.22	1,485	0.46	137,201	12.76
Depreciation and amortization	32,410	6.01	19,994	6.25	40,628	3.78
Transmission and distribution costs	33,091	6.13	27,206	8.50	25	—
Taxes other than income taxes	14,210	2.63	8,716	2.72	11,430	1.06
Income taxes	28,053	5.20	5,349	1.67	25,320	2.35
Total non-fuel operating expenses	152,846	28.33	105,991	33.13	244,613	22.75
Operating income	$ 56,827	10.53%	$ 18,600	5.81%	$ 80,359	7.47%

YEAR ENDED DECEMBER 31, 1999:

	Utility				Generation and Trading	
	Electric		Gas			
Operating revenues:						
External customers	$ 540,868	99.87%	$ 236,711	100.00%	$ 371,109	53.79%
Intersegment revenues	707	0.13	—	—	318,872	46.21
Total revenues	541,575	100.00	236,711	100.00	689,981	100.00
Cost of energy sold	4,493	0.83	112,925	47.71	414,534	60.08
Intersegment purchases	318,872	58.88	—	—	707	0.10
Total fuel costs	323,365	59.71	112,925	47.71	415,241	60.18
Gross margin	218,210	40.29	123,786	52.29	274,740	39.82
Administrative and other costs	52,586	9.71	49,716	21.00	26,791	3.88
Energy production costs	2,632	0.49	1,504	0.64	132,787	19.25
Depreciation and amortization	31,113	5.74	19,210	8.12	40,253	5.83
Transmission and distribution costs	31,013	5.73	28,227	11.92	23	—
Taxes other than income taxes	19,014	3.51	6,915	2.92	9,006	1.31
Income taxes	24,082	4.45	2,112	0.89	7,319	1.06
Total non-fuel operating expenses	160,440	29.62	107,684	45.49	216,179	31.33
Operating income	$ 57,770	10.67%	$ 16,102	6.80%	$ 58,561	8.49%

YEAR ENDED DECEMBER 31, 1998:

	Utility				Generation and Trading	
	Electric		Gas			
Operating revenues:						
External customers	$ 555,568	99.87%	$ 255,975	100.00%	$ 279,636	43.53%
Intersegment revenues	707	0.13	-	-	362,722	56.47
Total revenues	556,275	100.00	255,975	100.00	642,358	100.00
Cost of energy sold	4,572	0.82	134,755	52.64	305,525	47.56
Intersegment purchases	362,722	65.21	-	-	707	0.11
Total fuel costs	367,294	66.03	134,755	52.64	306,232	47.67
Gross Margin	188,981	33.97	121,220	47.36	336,126	52.33
Administrative and other costs	44,632	8.02	46,941	18.34	25,739	4.01
Energy production costs	846	0.15	233	0.09	148,667	23.14
Depreciation and amortization	30,586	5.50	14,961	5.84	37,114	5.78
Transmission and distribution costs	31,985	5.75	24,341	9.51	130	0.02
Taxes other than income taxes	20,592	3.70	7,007	2.74	9,752	1.52
Income taxes	19,954	3.59	8,685	3.39	23,262	3.62
Total non-fuel operating expenses	148,595	26.71	102,168	39.91	244,664	38.09
Operating income	$ 40,386	7.26%	$ 19,052	7.44%	$ 91,462	14.24%

UTILITY OPERATIONS

electric

Operating revenues declined $2.1 million (0.4%) for the year to $539.5 million due to the implementation in late July 1999 of the rate order lowering rates by $22.2 million year-over-year. This was mostly offset by increased retail electricity delivery of 7.1 million MWh compared to 6.8 million MWh delivered in the prior year period, a 4.2% improvement which increased revenues $21.8 million year-over-year. This increased volume was the result of weather-related consumption and load growth.

The gross margin, or operating revenues minus cost of energy sold, decreased $8.5 million reflecting a decrease in gross margin as a percentage of revenues of 1.4%. This decline reflects the rate reduction discussed above, and an increase in intersegment transfer pricing. The Company's Generation and Trading Operations exclusively provide power to the Company's Electric Product Offering. Intersegment purchases for the Generation and Trading Operations are priced using internally developed transfer pricing and are not based on market rates. Customer rates for electric service are set by the PRC based on the recovery of the cost of power production and a rate of return that includes certain generation assets that are part of Generation and Trading Operations, among other things.

Administrative and general costs decreased $8.7 million (16.6%) for the year. This decrease is due to non-recurring Year 2000 ("Y2K") compliance costs and non-recurring costs related to the Company's implementation of its new customer billing system in 1999. In addition, in 1999, as a result of a significant increases in delinquent accounts due to system implementation problems, the Company incurred additional bad debt costs of $5.5 million above its normal experience rate. Bad debt expense in 2000 was $4.9 million, a 29.9% decline for the year (see "Implementation of New Billing System" below for additional discussion). As a percentage of revenues, administrative and other costs decreased to 8.1% from 9.7% for the year ended December 31, 2000 and 1999, respectively, primarily as a result of reduced costs.

Energy production costs decreased $1.4 million (54.1%) for the year primarily due to non-recurring Y2K compliance costs in 2000. As a percentage of revenues, energy production costs decreased from 0.5% to 0.2%.

Depreciation and amortization increased $1.3 million (4.2%) for the year. The increase is due to the impact of amortizing the costs of the new customer billing system, which has a five-year amortization life, and depreciating the expansion of the electric distribution system. Depreciation and amortization as a percentage of revenues increased from 5.7% to 6.0%.

Transmission and distribution costs increased $2.1 million (6.7%) for the year primarily due to increased scheduled maintenance of transmission lines and the addition of station related equipment for reliability purposes. This increase in scheduled maintenance is expected to continue in 2001. As a percentage of revenues, transmission and distribution costs increased from 5.7% to 6.1%.

Taxes other than income decreased $4.8 million (25.3%) due to a change in the recognition of electric franchise fees collected from customers and due to municipalities, partially offset by the impact of the implementation of the new customer billing system on the collection of certain taxes and an increase in expected tax liabilities. Franchise fees were a part of the Company's rate structure in the prior year. In the current year, they have been unbundled from the rate structure. As a result, the Company is now a collection agent for the municipalities taxes and does not incur expense or generate revenues as a result of collecting the fees. Taxes other than income as a percentage of revenues decreased to 2.6% from 3.5%.

gas

Operating revenues increased $83.2 million (35.2%) for the year to $319.9 million. This increase was driven by a 31.3% increase in the average rate charges per decatherm due to high gas prices in the later months of 2000 as a result of increased market demand, a 3.0% volume increase and a gas rate increase which became effective October 30, 2000. Residential and commercial customers volume decreased 10.5% due to unseasonably warm weather during the early part of 2000. Customer volume, other than residential and commercial, increased 14.9%. This growth was primarily attributed to industrial and transportation customers such as the Company's Generation and Trading Operations whose increased demand was driven by the strong power market in the Western United States. Such growth is unlikely to recur in 2001.

The gross margin, or operating revenues minus cost of energy sold, increased $0.8 million (0.7%). This increase is due to higher distribution volumes on which the Company earns cost of service revenues. The Company purchases natural gas in the open market and resells it at cost to its distribution customers. As a result, the increase in gas prices driving increased cost of sales revenues does not have an impact on the Company's gross margin or earnings. In addition, the rate increase partially contributed to the increase in gross margin.

Administrative and general costs decreased $6.5 million (13.0%). This decrease is mainly due to non-recurring Y2K compliance costs, customer billing system costs and lower associated bad debt costs. The Electric and Gas Product Offerings share the same billing system, and the Gas Product Offering experienced the same delinquency problems discussed above in the "Electric Product Offering" results of operations. As a result in 1999, the Company incurred additional bad debt costs of $2.7 million above its normal experience rate. However, bad debt expense did not significantly decline in 2000 as the Company increased its bad debt costs by approximately $2 million in anticipation of a higher than normal delinquency rate driven by the significantly higher natural gas prices experienced in November and December 2000. This trend is similar to historic collection trends associated with past gas price spikes.

Depreciation and amortization increased $0.8 million (4.1%) for the year. The increase is due to the impact of amortizing the costs of a new customer billing system and depreciating the expansion of the gas transmission system.

Transmission and distribution costs decreased $1.0 million (3.6%) primarily due to non-recurring Y2K compliance costs.

Taxes other than income increased $1.8 million (25.5%) primarily due to higher tax liabilities and the impact of the implementation of the new customer billing system on the collection of certain taxes.

GENERATION AND TRADING OPERATIONS

Operating revenues grew $385.2 million (55.8%) for the year to $1.08 billion. This increase in wholesale electricity sales reflects strong regional wholesale electric prices caused by a warm summer, limited power generation capacity, increasing natural gas prices and the power supply imbalance in the Western United States. These factors contributed to unusually high wholesale prices which the Company does not believe to be sustainable in the long-term, but continue to effect markets in 2001. In addition, these factors have led to an extremely volatile wholesale electric power market with significant risk (see Other Issues Facing the Company – Western United States Wholesale Power Market). The Company delivered wholesale (bulk) power of 12.4 million MWh of electricity this period compared to 11.2 million MWh delivered last year, an increase of 10.6%. The MWh increase is attributable to increased trading activity during the year. Wholesale revenues from third-party customers increased from $371.1 million to $750.4 million, a 102.2% increase. The increase was largely price driven.

The gross margin, or operating revenues minus cost of energy sold, increased $50.2 million (18.3%). Higher margins were partially offset by $8.5 million of losses associated with the Company's assessment of risk in the wholesale market (see Other Issues Facing The Company – Western United States Wholesale Power Market) and unrealized mark-to-market losses of $4.8 million which the Company recognized relating to its power trading contracts (see Note (5) of the Notes to Consolidated Financial Statements). These items were recorded as revenue adjustments. Gross margin as a percentage of revenues decreased from 39.8% to 30.2% reflecting higher fuel and purchased power costs due to higher wholesale sales volumes and scheduled outages at the Company's SJGS and Four Corners. The Company expects similar planned outages in 2001.

Administrative and general costs increased $3.2 million (12.0%) for the year. This increase is due to a one-time charge of $4.5 million in connection with the acquisition of a new, long-term wholesale customer (see Note (11) of the Notes to Consolidated Financial Statements) and an increase in bad debt costs, partially offset by lower legal costs related to a lawsuit settlement involving the Company's decommissioning trust (which was settled in August 2000; see Consolidated Results of Operations discussion) and non-recurring Y2K compliance costs. As a percentage of revenues, administrative and other costs decreased to 2.8% from 3.9% for the year ended December 31, 2000 and 1999, respectively as a result of increased revenues.

Energy production costs increased $4.4 million (3.3%) for the year. These costs are generation related. The increase is due to higher maintenance costs resulting from scheduled outages at SJGS Unit 3 and Four Corners Unit 4, which were partially offset by lower PVNGS employee costs as a result of additional employee incentive and retiree healthcare costs in the prior year that did not recur in 2000 and additional PVNGS billings in 1999 for 1998 expenses as a result of an audit by the station owners. As a percentage of revenues, energy production costs decreased from 19.3% to 12.8%. The decrease is primarily due to a significant increase in energy sales.

Taxes other than income increased $2.4 million (26.9%) due to higher tax liabilities. Taxes other than income as a percentage of revenues decreased slightly from 1.3% to at 1.1% as a result of the increase in energy sales.

UNREGULATED BUSINESSES

Avistar contributed $2.2 million in revenues for the year compared to $8.9 million in the comparable prior year period due to lower business volumes resulting from slow developing markets associated with Avistar's new product offerings. Operating losses for Avistar increased from $4.4 million in the prior year to $6.6 million in the current year.

CONSOLIDATED

Corporate administrative and general costs, which represent costs that are driven exclusively by corporate-level activities, increased $8.0 million for the year. This increase was due to additional administrative and consulting expenses for strategic initiatives, higher legal costs and reorganizational costs incurred in anticipation of separating utility operations under the Restructuring Act.

Other income and deductions, net of taxes, increased $4.2 million for the year to $34.4 million due to gains, $13.2 million before income taxes related to the settlement of a lawsuit (see "Other Issues Facing the Company – Nuclear Decommissioning Trust") and $4.6 million before income taxes associated with the resolution of two gas rate cases (see "Other Issues Facing The Company – Gas Rate Orders"). The current year also had increased mark-to-market gains on the corporate hedge (see "Note 5 to the Consolidated Financial Statements"). These increases were partially offset by $6.7 million before income taxes of costs related to the Company's proposed acquisition of Western Resources' electric utility assets. The Company expects to continue to incur acquisition related costs in 2001 and beyond. While these costs were deductible for income tax purposes in 2000, a significant portion of these future costs may not be tax deductible. In addition, other income and deductions included a valuation loss recognized for Avistar's AMDAX.com investment, and expenses related to the transfer of the operation of the city of Santa Fe's water system to the municipality. In 1999, other income and deductions included gains, net of taxes, of $4.2 million of equity income from a passive investment and $1.2 million from closing down certain coal mine reclamation activities in an inactive subsidiary.

Net interest charges decreased $4.7 million for the period to $65.9 million primarily as a result of the retirement of $31.6 million of senior unsecured notes ("SUNS") in June and August 1999 and $32.8 million in January 2000.

The Company's consolidated income tax expense, before the cumulative effect of an accounting change, was $74.3 million, an increase of $32.0 million for the year. The Company's 2000 income tax effective rate, before the cumulative effect of the accounting change, was 42.4%. Included in the Company's 2000 income tax expense is the write-off of $6.6 million of income tax related regulatory assets. These assets relate to pre-1981 electric utility rate adjustments for certain tax benefits. The write-off of these assets reflects management's view of the probable financial outcome of utility deregulation in New Mexico, based on existing circumstances. Excluding the write-off of income tax related regulatory assets, the Company's effective tax rate was 38.7%. The Company's 1999 effective tax rate was 34.7%. The increase in the rate was primarily due to the favorable tax treatment received on the 1999 equity earnings discussed above.

The Company's net earnings from continuing operations for the year ended December 31, 2000 were $100.9 million, a 26.8% increase. These results were impacted by certain special items comprised of gains from the settlement of a lawsuit and the favorable resolution of two gas rate cases and charges related to the impairment of certain regulatory assets, the acquisition of a new, long-term wholesale customer and the proposed acquisition of Western Resources' ("2000 Special Items"). The Company's net earnings excluding the 2000 Special Items were $102.6 million. Net earnings for the year ended December 31, 1999 included certain special items comprised of gains related to equity income from a passive investment and mine closure activities and bad debt costs associated with system implementation problems ("1999 Special Items"). Net earnings from continuing operations excluding the 1999 and 2000 Special Items increased from $78.5 million in 1999 to $102.6 million in 2000.

Earnings per share from continuing operations excluding the cumulative effect of the accounting change on a diluted basis were $2.58 (excluding the 2000 Special Items) for the year ended December 31, 2000 compared to $1.91 (excluding the 1999 Special Items) for the year ended December 31, 1999. Diluted weighted average shares outstanding were 39.7 million and 41.1 million in 2000 and 1999, respectively. The decrease reflects the common stock repurchase program in 1999 and 2000. Net earnings per share from continuing operations primarily increased due to expansion of the Company's wholesale energy trading activities and the common stock repurchase program.

UTILITY OPERATIONS

electric

Operating revenues decreased $14.8 million (2.6%) for the year to $541.6 million primarily due to the implementation of a new rate order in late July 1999 (which lowered rates by $18 million year over year). The rate reduction was partially offset by an increase in volume. Retail electricity delivery was 6.8 million MWh compared to 6.7 million MWh delivered last year, a 1.5% improvement. Sales volume growth was negatively impacted by cooler temperatures during the summer months.

The gross margin, or operating revenues minus cost of energy sold, increased $29.2 million (15.5%) reflecting an increase in gross margin as a percentage of revenues of 6.3%. This increase reflects a decrease in intersegment transfer prices, partially offset by the rate reduction discussed above. The Company's Generation and Trading Operations exclusively provide power to the Company's Electric Product Offering. Intersegment purchases for the Generation and Trading Operations are priced using internally developed transfer pricing and are not based on market rates.

Administrative and general costs increased $8.0 million (17.8%) for the year. This increase is due to Y2K compliance costs and costs related to the Company's implementation of its new customer billing system. In addition, the Company incurred incremental bad debt costs throughout 1999 of $5.5 million as a result of a significant increase in delinquent accounts due to system implementation problems (see "Implementation of New Billing System" below for additional discussion). As a percentage of revenues, administrative and general costs increased from 8.0% to 9.7%.

Energy production costs increased $1.8 million for the year primarily due to Y2K compliance costs in 1999. As a percentage of revenues, energy production costs increased from 0.2% to 0.5%.

Depreciation and amortization increased $0.5 million (1.7%) for the year. The increase is due to the impact of the new customer billing system. As a result of this, the Company revised its depreciation rates as required by the PRC. Depreciation and amortization as a percentage of revenues increased from 5.5% to 5.7% largely reflecting the decrease in energy sales.

Transmission and distribution costs decreased $1.0 million (3.0%) for the year. This was primarily the result of lower maintenance costs due to the milder weather. As a percentage of revenues, transmission and distribution costs remained relatively constant at 5.7% and 5.8% for the years ended December 31, 1999 and 1998, respectively.

gas

Operating revenues declined $19.3 million (7.5%) for the year to $236.7 million. This decline was driven by a 13.8% decline in the average rate charges per decatherm due to weak gas prices and a mild winter. Price declines were partially offset by a 7.7% volume improvement, as transportation volume posted double-digit growth of 10.3%.

The gross margin, or operating revenues minus cost of energy, increased $2.6 million (2.1%). This increase is due to changes in access fee options and increased volume sales.

Administrative and general increased $2.8 million (5.9%). This increase is mainly due to Y2K compliance costs and costs related to the Company's implementation of its new customer billing system. In addition, the Company incurred higher bad debt costs throughout 1999 of $2.7 million, as a result of a significant increase in delinquent accounts due to system implementation problems (see "Implementation of New Billing System" below for additional discussion).

Depreciation and amortization increased $4.2 million (28.4%) for the year. The increase is due to the impact of the new customer billing system. As a result of the addition, the Company revised its depreciation rates as required by the PRC.

Transmission and distribution expenses increased $3.9 million (16.0%) for the year. The increase is primarily due to Y2K compliance costs.

GENERATION AND TRADING OPERATIONS

Operating revenues grew $47.6 million (7.4%) for the year to $690.0 million due to an improvement in wholesale electricity sales volume. The Company delivered wholesale (bulk) power of 11.2 million MWh of electricity this year compared to 8.8 million MWh delivered last year, an increase of 27.2%. Revenue growth was negatively impacted by cooler temperatures in the southwest during the summer months and the availability of abundant hydro power that negatively impacted market prices in the Western United States.

The gross margin, or operating revenues minus cost of energy, decreased $61.4 million reflecting a decrease in gross margin as a percentage of revenues of 23.9%. This decline reflects higher fuel and purchased power costs as a result of increased sales and higher prices.

Administrative and general costs increased $1.1 million (4.1%) for the year. This increase is due to Y2K compliance costs and higher legal costs related to a lawsuit involving the Company's decommissioning trust. These increases were offset by an additional allocation of costs for 1998 and 1999 to the participants in the jointly-owned SJGS following an audit by the owners of the station. As a percentage of revenues, administrative and general costs decreased from 4.0% to 3.9% primarily due to the increase in sales.

Energy production costs decreased $15.9 million (10.7%) for the year. These costs are generation related. The decrease is primarily due to reduced nuclear fuel storage costs at PVNGS. In 1998, the Company incurred costs of $12.1 million for spent nuclear fuel at PVNGS as it was determined that alternatives to the United States Department of Energy ("DOE") storage and disposal facilities would be necessary due to the DOE's failure to complete such facilities by 1998 as required by law. These costs represent the cost of storage for spent fuel through 1998. As a percentage of revenues, energy production costs decreased from 23.1% to 19.3%. The decrease is due to cost control and the decreased nuclear fuel storage costs and the increase in sales.

Depreciation and amortization increased $3.1 million (8.5%) for the year. The increase is due to pollution control improvements at certain generation plants. As a result of the additions, the Company revised its depreciation rates as required by the PRC. Depreciation and amortization as a percentage of revenues remained constant at 5.8% reflecting an increase in expense offset by the increase in energy sales.

UNREGULATED BUSINESSES

Avistar contributed $8.9 million in revenues in 1999 compared to $1.3 million in 1998. Operating loss for the unregulated businesses decreased from $5.9 million in 1998 to $4.4 million in 1999 reflecting their expanded operating activities.

CONSOLIDATED

Corporate administrative and general costs remained relatively constant at $12.7 million for the year.

Other income and deductions, net of taxes, increased $7.5 million for the year to $30.2 million due to the recording of interest income from the PVNGS Capital Trust. In addition, other income included certain one-time net gains in 1999 and 1998. In 1999, the Company recognized $4.2 million of equity income from a passive investment and a gain of $1.2 million as a result of closing down of coal mining reclamation activities in an inactive subsidiary. In 1998, the Company recognized $1.3 million in a lawsuit settlement and $1.5 million from the reversal of a gas rate case reserve.

Net interest charges increased $7.5 million for the year to $70.7 million as a result of the issuance of $435 million in SUNS in August 1998, which replaced first mortgage bonds with a lower interest rate, and the issuance of pollution control revenue bonds of $11.5 million in October 1999. This was partially offset by the retirement of $31.6 million of SUNS in June and August 1999 and a decrease in short-term debt interest charges due to lower short-term borrowings in 1999.

The Company's consolidated income tax expense, before the cumulative effect of accounting change and discontinued operations, was $42.3 million, a decrease of $14.0 million for the year. The Company's income tax effective rate, before the cumulative effect of accounting change and discontinued operations, decreased from 37.2% to 34.7%. This decrease is primarily due to the favorable tax treatment received on the equity income discussed above. The investment income qualifies for the 80% dividends received deduction under Internal Revenue Service regulations.

The Company's net earnings from continuing operations for the year ended December 31, 1999, were $78.5 million, excluding the one-time gains related to equity income from a passive investment and mine closure activities and the one-time charge for bad debt associated with system implementation problems ("1999 Special Items") compared to $99.0 million, excluding one-time gains for proceeds from a litigation settlement and the reversal of a gas rate case reserve and the one-time charge for spent nuclear fuel costs at PVNGS ("1998 Special Items") for the year ended December 31, 1998.

Earnings per share from continuing operations on a diluted basis excluding the cumulative effect of the accounting change were $1.91 (excluding the 1999 Special Items) for the year ended December 31, 2000 compared to $2.35 (excluding the 1998 Special Items) for the year ended December 31, 1998. Diluted weighted average shares outstanding were 41.1 million and 42.1 million in 1999 and 1998, respectively. The decrease reflects the common stock repurchase program in 1999. The 1999 results were negatively impacted by the electric rate reduction in the third quarter, increased fuel and purchased power costs, a weak gas market and cooler weather in the West during the summer months. In addition, Y2K compliance and the implementation of the new customer billing system increased costs. This impact was partially offset by the gains recorded in other income.

discontinued operations

In August 1998, the Company adopted a plan to discontinue the natural gas trading operations of its Energy Services Business Unit and completely discontinued these operations on December 31, 1998. Losses from discontinued operations, net of taxes, for the year ended December 31, 1998, were $12.4 million, or $0.30 per common share. These losses did not recur in 1999.

cumulative effect of a change in accounting principle

Effective January 1, 1999, the Company adopted Energy Issues Task Force ("EITF") Issue No. 98-10. The effect of the initial application of the new standard is reported as a cumulative effect of a change in accounting principle. As a result, the Company recorded additional earnings, net of taxes, of approximately $3.5 million, or $0.08 per common share, to recognize the gain on net open physical electricity purchase and sales commitments considered to be trading activities.

On January 27, 2001, the Company announced that it expected its 2001 earnings to be within the range of $2.60 to $2.70 per diluted share. This estimate is based on the Company's strong results in 2000, and management's view of developments in the wholesale power marketplace in the beginning of 2001. Management believes that the strong wholesale power market experienced in the third and fourth quarters of 2000 will continue into the first two quarters of 2001, while the third and fourth quarters of 2001 are not expected to experience the demand that drove wholesale power prices in the comparable quarters in 2000; therefore, management's expectation is that the third and fourth quarters' net earnings may be lower than in 2000. The Company's wholesale power marketing operations are expected to continue to expand in 2001. Accordingly, these earnings expectations factor in the anticipated continued volatility seen in the wholesale marketplace in 2000, and appropriate allowances have been made in these estimates for this market risk, similar in nature to the $8.5 million of losses recognized for market risk in 2000.

Management's expectations for 2001 assume retail sales growth will continue at rates comparable to what was experienced in 2000 and the full realization of the favorable outcome of the two gas rate cases settled in August of 2000. Expenses are expected to increase due to inflation, growth initiatives and regulatory filing costs. These earnings estimates do not include any costs related to the Company's acquisition of the electric utility assets of Western Resources which are expected to be approximately $10 to $15 million. The significant capital additions in 2000 are expected to result in increased depreciation and amortization expense in 2000. In addition, because of initiatives undertaken in 2000, it is expected that reduced losses in the non-regulated businesses will contribute to net earnings.

This discussion of future expectations is forward looking information within the meaning of Section 21E of the Securities and Exchange Act. The achievement of expected results is dependent upon the assumptions described in the preceding discussion, and is qualified in its entirety by the Private Securities Litigation Reform Act of 1995 disclosure – (see "Disclosure Regarding Forward Looking Statements" on page 39) – and the factors described within the disclosure which could cause the Company's actual financial results to differ materially from the expected results enumerated above.

At December 31, 2000, the Company had working capital of $147.8 million including cash and cash equivalents of $107.7 million. This is a decrease in working capital of $19.3 million from December 31, 1999. This decrease primarily reflects the Company's increased activity in the wholesale power market.

Cash generated from operating activities was $239.5 million, an increase of $26.5 million from 1999. This increase was primarily the result of increased profitability including the favorable settlement of a lawsuit. In addition, accounts payable increased due to increased wholesale power purchases driven by the Company's expansion of its wholesale power marketing operations. This increase was partially offset by an increase in the Company's receivables. Unrecovered purchased gas adjustments and accounts receivable from utility customers increased as a result of higher gas prices. In addition, accounts receivable increased as a result of increased wholesale electricity sales.

Cash used for investing activities was $157.5 million in 2000 compared to $55.9 million in 1999. This increased spending reflects $13.3 million related to the acquisition of transmission assets (see "Acquisition of Certain Assets and Related Agreements" below), combustion turbine option payments of $13.0 million, the expansion of the electric distribution system at a cost of $13.7 million and the gas transmission and distribution systems at a cost of $10.1 million to serve new load and for reliability purposes, an investment in an internet gateway service provider of $10.0 million and additional funding and realized gains in the decommissioning trust of $9.3 million. Cash used for investing activities in 2000 includes the $6.7 million of costs related to the acquisition of Western Resources electric utility assets. In addition, in 1999 the Company liquidated certain insurance-based investments in the nuclear decommissioning trust of $26.6 million.

Cash used for financing activities was $94.7 million in 2000 compared to $98.0 million in 1999. This decrease reflects $26.6 million of loan repayments associated with nuclear decommissioning trust activities in 1999, partially offset by the issuance of $11.5 million of 6.60% Pollution Control Revenue Bonds in 1999 and increased common stock repurchases in 2000 (see "Stock Repurchase" below).

CAPITAL REQUIREMENTS

Total capital requirements include construction expenditures as well as other major capital requirements and cash dividend requirements for both common and preferred stock. The main focus of the Company's construction program is upgrading generation systems, upgrading and expanding the electric and gas transmission and distribution systems and purchasing nuclear fuel. In addition, the Company anticipates significant expenditures to expand its generation capabilities.

Projections for total capital requirements and construction expenditures for 2001 are $353 million and $347 million, respectively. Such projections for the years 2001 through 2005 are $1.45 billion and $1.42 billion, respectively. These estimates are under continuing review and subject to on-going adjustment (see "Competitive Strategy" above).

The Company's construction expenditures for 2000 were entirely funded through cash generated from operations. The Company currently anticipates that internal cash generation and current debt capacity will be sufficient to meet capital requirements for the years 2001 through 2005, except as provided for in its proposed plan to separate pursuant to the Restructuring Act (see "Proposed Holding Company Plan" below). To cover the difference in the amounts and timing of cash generation and cash requirements, the Company intends to use short-term borrowings under its liquidity arrangements.

LIQUIDITY

At February 1, 2001, the Company had $175 million of available liquidity arrangements, consisting of $150 million from a senior unsecured revolving credit facility ("Credit Facility"), and $25 million in local lines of credit. The Credit Facility will expire in March 2003. There were no outstanding borrowings as of February 1, 2001.

The Company's ability to finance its construction program at a reasonable cost and to provide for other capital needs is largely dependent upon its ability to earn a fair return on equity, results of operations, credit ratings, regulatory approvals and financial market conditions. Financing flexibility is enhanced by providing a high percentage of total capital requirements from internal sources and having the ability, if necessary, to issue long-term securities, and to obtain short-term credit.

In connection with the Company's announcement of its proposed acquisition of Western Resources' electric utility operations, Standard and Poors ("S&P"), Moody's Investor Services ("Moody's") and Fitch IBCA, Duff & Phelps ("Fitch") have placed the Company's securities ratings on negative credit watch pending review of the transaction. The Company is committed to maintaining its investment grade. S&P has rated the Company's senior unsecured debt and its EIP senior secured debt "BBB-" and its preferred stock "BB". Moody's has rated the Company's senior unsecured notes and senior unsecured pollution control revenue bonds "Baa3"; and preferred stock "ba1". The EIP lease obligation bonds are also rated "Ba1". Fitch rates the Company's senior unsecured notes and senior unsecured pollution control revenue bonds "BBB-," the Company's EIP lease obligation "BB+" and the Company's preferred stock "BB-." Investors are cautioned that a security rating is not a recommendation to buy, sell or hold securities, that it may be subject to revision or withdrawal at any time by the assigning rating organization, and that each rating should be evaluated independently of any other rating.

In addition to the impact of the proposed acquisition of Western Resources' electric utility operations, future rating actions for the Company's securities will depend in large part on the actions of the PRC relating to numerous restructuring issues, including the Company's proposed plan to separate the utility into a generation business and a distribution and transmission business as required by the Restructuring Act ("Proposed Plan"). The Company believes, based on its Proposed Plan (see "Proposed Holding Company Plan" below), that UtilityCo and PowerCo will both receive investment grade credit ratings, however, such ratings will be contingent upon many factors that have yet to be determined. Fitch announced publicly that assuming the Company implements its Proposed Plan, it would expect to issue investment grade ratings for UtilityCo, and PowerCo's rating would "border investment grade". Fitch cautioned that ratings for UtilityCo and PowerCo were highly conditional upon reaching assumptions provided by the Company.

Covenants in the Company's PVNGS Units 1 and 2 lease agreements limit the Company's ability, without consent of the owner participants in the lease transactions: (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions. The Credit Facility imposes similar restrictions regardless of credit ratings.

FINANCING ACTIVITIES

In January 2000, the Company reacquired $34.7 million of its 7.5% senior unsecured notes through open market purchases at a cost of $32.8 million.

The Company currently has no requirements for long-term financings during the period of 2001 through 2004, except as part of its Proposed Plan (see "Proposed Holding Company Plan" below). However, during this period, the Company could enter into long-term financings for the purpose of strengthening its balance sheet and reducing its cost of capital. The Company continues to evaluate its investment and debt retirement options to optimize its financing strategy and earnings potential. No additional first mortgage bonds may be issued under the Company's mortgage. The amount of SUNs that may be issued is not limited by the SUNs indenture. However, debt to capital requirements in certain of the Company's financial instruments would ultimately restrict the Company's ability to issue SUNs.

PROPOSED HOLDING COMPANY PLAN

On April 18, 2000, the Company filed as an exhibit on Form 8-K, unaudited pro forma financial statements of PowerCo and UtilityCo that give effect to the Company's Proposed Plan. The structure of the Proposed Plan presented in the April 18, 2000 Form 8-K was subsequently revised in October 2000 by the Company. This revised Proposed Plan results in a capital structure for the holding company, PowerCo and UtilityCo similar to the presentation in the Form 8-K. The revised Proposed Plan is subject to regulatory and other approvals as well as market, economic and business conditions. As such, the revised Proposed Plan may be subject to significant changes before implementation and the pro forma financial statements as filed in the Form 8-K may require revision to reflect the final plan of separation pursuant to the Restructuring Act.

The revised Proposed Plan assumes that the separation required under the Restructuring Act will be accomplished as follows: PowerCo will transfer its regulated assets to a wholly owned subsidiary, UtilityCo, in exchange for common stock, UtilityCo preferred stock, UtilityCo senior unsecured notes and cash. UtilityCo will also assume certain liabilities associated with the regulated assets. PowerCo will then dividend the common stock of UtilityCo to the holding company.

The current holders of PowerCo's public SUNs will be offered the opportunity to exchange their approximately $368 million of existing SUNs for $368 million of SUNs issued by UtilityCo with like terms and conditions. The current holders of PowerCo's preferred stock will be offered the opportunity to exchange their approximately $12.8 million of preferred stock for preferred stock issued by UtilityCo with like terms and conditions.

Although there are other alternatives to finance the acquisition of the regulated assets from PowerCo, based on current market, economic and business conditions, the Company currently believes that the foregoing transactions represent the most advantageous way to effect the Asset Transfer. However, the structure of the revised Proposed Plan is subject to change as the regulatory approval process continues and is ultimately resolved. Implementation of the Proposed Plan in 2001 is dependent on the outcome of certain pending legislation which if enacted, would delay restructuring for five more years.

A condition precedent to corporate separation is the obtaining of written consents from PVNGS lessors. As of December 31, 2000, two lessors had signed consents, one lessor has agreed in principle to the terms of the signed consent but had not signed, and two lessors had not agreed to those terms. The signed consents have various financial covenants which limit PowerCo's ability to sell, transfer or convey its assets assuming certain coverage ratios are not met. Additionally, the consents require the holding company to guarantee the leases. The consents and the covenants will not become effective until corporate separation occurs.

STOCK REPURCHASE

In March 1999, the Company's Board of Directors approved a plan to repurchase up to 1,587,000 shares of the Company's outstanding common stock with maximum purchase price of $19.00 per share. In December 1999, the Company's Board of Directors authorized the Company to repurchase up to an additional $20.0 million of the Company's common stock. As of December 31, 1999, the Company repurchased 1,070,700 shares of its previously outstanding common stock at a cost of $18.8 million. From January 2, 2000 through March 31, 2000, the Company repurchased an additional 1,167,684 shares of its outstanding common stock at a cost of $18.9 million. The Company has repurchased all shares authorized in March 1999 and December 1999 by the Board of Directors.

On August 8, 2000, the Company's Board of Directors approved a plan to repurchase up to $35 million of the Company's common stock through the end of the first quarter of 2001. From August 8, 2000 through December 31, 2000 Company repurchased an additional 417,900 shares of its outstanding common stock at a cost of $9.0 million. As of February 1, 2001, the Company does not anticipate continuing its repurchase plan given the share price of its common stock.

ACQUISITION OF CERTAIN ASSETS AND RELATED AGREEMENTS

The Company and Tri-State Generation and Transmission Association, Inc. ("Tri-State") entered into an asset sale agreement dated September 9, 1999, pursuant to which Tri-State has agreed to sell to the Company certain assets acquired by Tri-State as the result of Tri-State's merger with Plains Electric Generation and Transmission Cooperative, Inc. ("Plains") consisting primarily of transmission assets, a fifty percent interest in an inactive power plant located near Albuquerque, and an office building. The purchase price was originally $13.2 million, subject to adjustment at the time of closing, with the transaction to close in two phases. On July 1, 2000, the first phase was completed, and the Company acquired the 50 percent ownership in the inactive power plant and the office building. The second phase relating to the transmission assets is expected to close in the first quarter 2001.

In addition, on July 1, 2000, the Company advanced $11.8 million to a former Plains cooperative member as part of an agreement for the Company to become the cooperative's power supplier. Approximately $4.5 million of this advance represents an inducement for entering into a 10 year power sales agreement. Accordingly, the Company expensed this amount in the third quarter as a business development cost. The remaining $7.5 million will be repaid over 10 years. If the cooperative terminates the contract early, the whole $11.8 million advance must be repaid to the Company.

DIVIDENDS

The Company's Board of Directors reviews the Company's dividend policy on a continuing basis. The declaration of common dividends is dependent upon a number of factors including the extent to which cash flows will support dividends, the availability of retained earnings, the financial circumstances and performance of the Company, the PRC's decisions on the Company's various regulatory cases currently pending, the effect of deregulating generation markets and market economic conditions generally. In addition, the ability to recover stranded costs in deregulation, future growth plans and the related capital requirements and standard business considerations will also affect the Company's ability to pay dividends. In addition, following the separation as required by the Restructuring Act, the ability of the proposed holding company, to pay dividends will depend initially on the dividends and other distributions that UtilityCo and PowerCo pay to the holding company.

CAPITAL STRUCTURE

The Company's capitalization, including current maturities of long-term debt, at December 31 is shown below:

	2000	1999
Common Equity	48.6%	46.7%
Preferred Stock	0.7	0.7
Long-term Debt	50.7	52.6
Total Capitalization*	100.0%	100.0%

Total capitalization does not include as debt the present value of the Company's lease obligations for PVNGS Units 1 and 2 and EIP which was $162 million as of December 31, 2000 and $165 million as of December 31, 1999.

The Company has filed its transition plan with the PRC pursuant to the Restructuring Act in three parts. In November 1999, the Company filed the first two parts of the transition plan with the PRC. Part one, which has been approved, requested approval to create Manzano and UtilityCo as wholly-owned shell subsidiaries of the Company. Part two of the Company's transition plan requested all PRC approvals necessary for the Company to implement the formation of the holding company structure, the share exchange and the separation plan. Part Two is awaiting a recommended decision by the hearing examiner. Under existing deadlines, the Company must separate its assets no later than August 1, 2001. The Company's management believes that implementation of the separation plan will not occur prior to August 1, 2001, and there is no assurance that implementation of the separation plan will occur by that time. On May 31, 2000, the Company filed with the PRC part three of the transition plan requesting approval for the recovery of stranded costs and other expenses associated with the transition to a competitive market, UtilityCo's rates for retail distribution services, the procurement of "standard offer service" power supplies for customers who do not select a power supplier and other issues required to be considered under the Restructuring Act. The Hearing Examiner has tentatively scheduled hearings on Part three to begin on June 6, 2001. Hearings are expected to last four to six weeks.

On August 17, 2000, the PRC staff and other parties filed a Joint Motion to Defer Commission Decision on Separation of Generation Assets and to extend the Standard Offer Update Deadline. The Joint Motion requested that the PRC not allow separation to occur until after the 2001 legislative session to allow the legislature to determine if any amendments to the Restructuring Act might be necessary in light of the high prices experienced last year in California. The 2001 legislative session began January 16 and ends March 17. On September 11, 2000, the Company filed its response to the Joint Motion, pointing out key differences between New Mexico's Restructuring Act and California's as well as differing circumstances between the two states. On September 26, 2000, the PRC conducted a workshop where numerous interested parties commented on the California experience and its relevance to New Mexico. To date, the PRC has not formally acted on the Joint Motion.

The New Mexico Legislature is currently considering various legislative initiatives that could delay open access and activities under the Restructuring Act, including corporate separation. Legislators are concerned by the turmoil in the California retail energy market. On February 14, 2001, Senate Bill 266, as amended, passed the Senate 39-0. The bill delays implementation of restructuring, including corporate separation, by an additional five years. The PRC would have the authority to delay for another year under certain circumstances. The amended bill would require the PRC to approve a holding company, without asset separation, by July 1, 2001. In addition, the amended bill allows utilities to engage in unregulated power generation business activities until corporate separation is implemented. The cost of new unregulated utility generation resources will serve as a cap on the price of new resources needed to serve retail customers until restructuring is implemented. Although the amended bill passed the Senate unanimously, the Company is unable to predict if it will pass the House of Representatives and in what form, and if passed by the House, if it will be signed by the Governor. If enacted in its current form, Senate Bill 266 will provide the Company with significant flexibility to pursue its growth strategy, despite the delay in restructuring.

The Company had been in discussions with the PRC staff and other parties in an attempt to arrive at a settlement agreement which addresses the concerns of the parties and allows separation to continue without significant delay. The discussions have not continued pending conclusion of the New Mexico Legislative session in mid March, 2001. However, if Restructuring is not delayed by the Legislature, it is likely the discussions will be revived. The potential outcome of any future discussions may be different from the plan the Company filed on May 31, 2000 and could potentially affect the realizability of certain regulatory assets recorded by the Company (See "Other Issues Facing the Company – The Restructuring Act and Formation of the Holding Company – Stranded Costs").

In addition to the PRC's approval, completion of corporate separation will require a number of regulatory approvals by, among others, the Securities and Exchange Commission ("SEC"). Approvals from the FERC and the Nuclear Regulatory Commission ("NRC") have been obtained. In June 2000, shareholders approved the share exchange; however, completion of corporate separation will also require certain other consents. Completion may also entail significant restructuring activities with respect to the Company's existing liquidity arrangements and the Company's publicly-held senior unsecured notes of which $368 million were outstanding as of December 31, 2000. Under the Proposed Plan, holders of the Company's senior unsecured notes, $100 million at 7.5% and $268.4 million at 7.1%, will be offered the opportunity to exchange their securities for like senior unsecured notes to be issued by the newly created regulated business (see "Liquidity and Capital Resources - Financing Activities and Proposed Holding Company Plan" above).

STRANDED COSTS

The Restructuring Act recognizes that electric utilities should be permitted a reasonable opportunity to recover an appropriate amount of the costs previously incurred in providing electric service to their customers ("stranded costs"). Stranded costs represent all costs associated with generation-related assets, currently in rates, in excess of the expected competitive market price over the life of those assets and include plant decommissioning costs, regulatory assets, and lease and lease-related costs. Utilities will be allowed to recover no less than 50% of stranded costs through a non-bypassable charge on all customer bills for five years after implementation of customer choice. The PRC could authorize a utility to recover up to 100% of its stranded costs if the PRC finds that recovery of more than 50%: (i) is in the public interest; (ii) is necessary to maintain the financial integrity of the public utility; (iii) is necessary to continue adequate and reliable service; and (iv) will not cause an increase in rates to residential or small business customers during the transition period. The Restructuring Act also allows for the recovery of nuclear decommissioning costs by means of a separate wires charge over the life of the underlying generation assets (see "NRC Prefunding" below).

The calculation of stranded costs is subject to a number of highly sensitive assumptions, including the date of open access, appropriate discount rates and projected market prices, among others. On May 31, 2000, the Company filed with the PRC its proposal to recover its stranded costs. These costs, excluding nuclear decommissioning costs, total a present value of $691.6 million. In addition, stranded costs associated with decommissioning the Company's portion of the

PVNGS nuclear plant total an additional present value of $44.4 million. This amount considers the effect of expected earnings on the Company's qualified nuclear decommissioning trusts.

Approximately $141 million of costs associated with the unregulated businesses under the Restructuring Act were established as regulatory assets. Because of the Company's belief that recovery is probable, these regulatory assets continue to be classified as regulatory assets, although the Company has discontinued Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71) and adopted Statement of Financial Accounting Standards No. 101, "Regulated Enterprises—Accounting for the Discontinuance of Application of FASB Statement 71." In 2000, the Company expensed $6.6 million of these assets based on management's view of the probable financial outcome of restructuring in New Mexico upon existing circumstances. If discussions with the PRC staff and other parties result in a settlement in which the amount the Company recovers for stranded costs is less than the amount it has recorded on the balance sheet as regulatory assets, the Company will be required to write–off the difference between its recovery of these costs and the amount it has currently recorded. Likewise, if a delay in corporate separation occurs, the Company may be required to write-off all or a portion of these assets due to the uncertainty of recovery resulting from enactment of the delay. However, Senate Bill 266, as amended, establishes certain regulatory provisions affecting these costs, which if enacted along with the delay, will allow the Company to recover mine reclamation costs (see "Note 2 to the Consolidated Financial Statements").

The Company believes that the Restructuring Act if properly applied provides an opportunity for recovery of a reasonable amount of stranded costs. If regulatory orders do not provide for a reasonable recovery, the Company is prepared to vigorously pursue judicial remedies. Final determination and quantification of stranded cost recovery has not been made by the PRC. The determination will have an impact on the recoverability of the related assets and may have a material effect on the future financial results and position of the Company.

TRANSITION COST RECOVERY

In addition, the Restructuring Act authorizes utilities to recover in full any prudent and reasonable costs incurred in implementing full open access ("transition costs"). These transition costs are currently scheduled to be recovered through 2007 by means of a separate wires charge. The PRC may extend this date by up to one year. The Company is still evaluating its expected transition costs and has not made a final determination of those costs. The Company, however, currently estimates that these costs will be approximately $46 million, including allowances for certain costs which are non-deductible for income tax purposes. To date, the Company has capitalized $19.1 million of expenditures that meet the Restructuring Act's definition of transition-related costs. Transition costs for which the Company will seek recovery include professional fees, financing costs, consents relating to the transfer of assets, management information system changes including billing system changes and public and customer education and communications. Recoverable transition costs are currently being capitalized and will be amortized over the recovery period to match related revenues. The Company intends to vigorously pursue remedies available to it should the PRC disallow recovery of reasonable transition costs. Costs not recoverable will be expensed when incurred unless these costs are otherwise permitted to be capitalized under current and future accounting rules. If the amount of non-recoverable transition costs is material, the resulting charge to earnings may have a material effect on the future financial results and position of the Company.

NRC PREFUNDING

Pursuant to NRC rules on financial assurance requirements for the decommissioning of nuclear power plants, the Company has a program for funding its share of decommissioning costs for PVNGS through a sinking fund mechanism. The NRC rules on financial assurance became effective on November 23, 1998. The amended rules provide that a licensee may use an external sinking fund as the exclusive financial assurance mechanism if the licensee recovers estimated decommissioning costs through cost of service rates or a "non-bypassable charge". Other mechanisms are prescribed, such as prepayment, surety methods, insurance and other guarantees, to the extent that the requirements for exclusive reliance on the fund mechanism are not met.

The Restructuring Act allows for the recoverability of 50% up to 100% of stranded costs including nuclear decommissioning costs (see "Stranded Costs"). The Restructuring Act specifically identifies nuclear decommissioning costs as eligible for separate recovery over a longer period of time than other stranded costs if the PRC determines a separate recovery mechanism to be in the public interest. In addition, the Restructuring Act states that it is not requiring the PRC to issue any order which would result in loss of eligibility to exclusively use external sinking fund methods for decommissioning obligations pursuant to Federal regulations. If the Company is unable to meet the requirements of the NRC rules permitting the use of an external sinking fund because it is unable to recover all of its estimated decommissioning costs through a non-bypassable charge, the Company may have to pre-fund or find a similarly capital intensive means to meet the NRC rules. There can be no assurance that such an event will not negatively affect the funding of the Company's growth plans.

In addition, as part of the determination and quantification of the stranded costs related to the decommissioning, the Company estimated its future decommissioning costs. If the Company's estimate proves to be less than the actual costs of decommissioning, any cost in excess of the amount allowed through stranded cost recovery may not be recoverable. Such excess costs, if any, will also be subject to the pre-funding requirements discussed above.

COMPETITION

Under current law, the Company is not in direct retail competition with any other regulated electric and gas utility. Nevertheless, the Company is subject to varying degrees of competition in certain territories adjacent to or within areas it serves that are also currently served by other utilities in its region as well as cooperatives, municipalities, electric districts and similar types of government organizations.

As a result of the Restructuring Act, the Company may face competition from companies with greater financial and other resources. There can be no assurance that the Company will not face competition in the future that would adversely affect its results.

It is the current intention to have the Company's unregulated businesses under the Restructuring Act engage primarily in energy-related businesses that will not be regulated by state or Federal agencies that currently regulate public utilities (other than the FERC and NRC). These competitive businesses, including the generation business, will encounter competition and other factors not previously experienced by the Company, and may have different, and perhaps greater, investment risks than those involved in the regulated business that will be engaged in by UtilityCo. Specifically, the passage of the Restructuring Act and deregulation in the electric utility industry generally are likely to have an impact on the price and margins for electric generation and thus, the return on the investment in electric generation assets. In response to competition and the need to gain economies of scale, electricity producers will need to control costs to maintain margins, profitability and cash flow that will be adequate to support investments in new technology and infrastructure. The Company will have to compete directly with independent power producers, many of whom will be larger in scale, thus creating a competitive advantage for those producers due to scale efficiencies.

The New Mexico Legislature is currently considering legislation that could delay open access and other activities under the Restructuring Act, including corporate separation. A delay without providing business flexibility could have a negative effect on the Company's ability to compete in the wholesale power market. Under the current regulatory environment in New Mexico, the Company is unable to achieve the necessary business flexibility it requires to take advantage of business opportunities to execute its growth strategy. There can be no assurance that the Company can successfully compete in the wholesale power marketplace and continue to execute its growth strategy if implementation of the Restructuring Act is rolled back. Senate Bill 266, as originally introduced, simply delayed restructuring for five years. However, during the course of committee hearings and floor debate, the bill was amended so as to provide significant business flexibility to utilities despite the delay. As amended, Senate Bill 266 passed the Senate 39-0 and is now pending in the House of Representatives.

Under the terms of an agreement and plan of restructuring and merger, the Company and Western Resources, whose utility operations consist of its Kansas Power and Light division and Kansas Gas and Electric subsidiary, will both become subsidiaries of a new holding company to be named at a future date. Prior to and as a condition to, the consummation of this combination, Western Resources will reorganize all of its non-utility assets, including its 85% stake in Protection One and its 45% investment in ONEOK, into Westar Industries which will be spun off to Western Resources' shareholders prior to the acquisition of Western's utility assets by the Company.

The new holding company will issue 55 million of its shares, subject to adjustment, to Western Resources' shareholders and Westar Industries and 39 million shares to the Company's shareholders. Before any adjustments, the new company will have approximately 94 million shares outstanding, of which approximately 41% will be owned by former Company shareholders and 59% will be owned by former Western Resources shareholders and Westar Industries.

Based on the Company's average closing price over the last ten days prior to the announcement of the transaction of $27.325 per share, the indicated equity consideration of the transaction is approximately $1.5 billion. In addition, approximately $2.9 billion of existing Western Resources debt will be retained, giving the transaction an aggregate enterprise value of approximately $4.4 billion.

The new company will undertake to refinance and reduce the debt on Western Resources' books. The new holding company will have a total enterprise value of approximately $6.5 billion ($2.6 billion in equity; $3.9 billion in debt and preferred stock).

The transaction will be accounted for as a reverse acquisition by the Company as the former Western Resources shareholders will receive the majority of the voting interests in the new holding company. For accounting purposes, Western Resources will be treated as the acquiring entity. Accordingly, all of the assets and liabilities of the Company will be recorded at fair value in the business combination as required by the purchase method of accounting. In addition, the operations of the Company will be reflected in the operations of the combined company only from the date of acquisition.

In the transaction, each Company share will be exchanged on a one-for-one basis for shares in the new holding company. The portion of each Western Resources share not converted into Westar stock in connection with the spin-off will be exchanged for a fraction of a share of the new holding company in accordance with an exchange ratio to be finalized at closing, depending on the impact of certain adjustments to the transaction consideration. Under the terms of the agreement, Western Resources and Westar Industries have been given an incentive to reduce Western Resources net debt balance prior to the consummation of the transaction. The agreement contains a mechanism to adjust the transaction consideration based on additional equity contributions. Under this mechanism, Western Resources could undertake certain activities not affecting its utility operations to reduce the net debt balance of the utility. The effect of such activities would be to increase the number of new holding company shares to be issued to all Western Resources shareholders (including Westar Industries) in the transaction. In addition, Westar Industries has the option of making additional equity infusions into Western Resources that will be used to reduce the utility's net debt balance prior to closing. Up to $407 million of such equity infusions may be used to purchase additional new holding company common and convertible preferred stock.

At closing, Jeffry E. Sterba, present chairman, president and chief executive officer of the Company, will become chairman, president and chief executive officer of the new holding company, and David C. Wittig, present chairman, president and chief executive officer of Western Resources, will become chairman, president and chief executive officer of Westar Industries. The Board of Directors of the new company will consist of six current Company board members and three additional directors, two of whom will be selected by the Company from a pool of candidates nominated by Western Resources, and one of whom will be nominated by Westar Industries. The new holding company will be headquartered in New Mexico. Headquarters for the Kansas utilities will remain in Kansas.

The Company expects that the shareholders of the new holding company will receive the Company's dividend. The Company's current annual dividend is $0.80 per share. There can be no assurance however that any funds, property or shares will be legally available to pay dividends at any given time or if available, the new holding company's Board of Directors will declare a dividend.

The companies expect the transaction to be completed within the next 12 to 18 months. The successful spin-off of Westar Industries from Western Resources is required prior to the consummation of the transaction. The transaction is also conditioned upon, among other things, approvals from both companies' shareholders and customary regulatory approvals from the Kansas Corporation Commission, the New Mexico Public Regulation Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The new holding company expects to register as a holding company with the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. The Company expects that all of the above mentioned approvals will be obtained; however, such approvals are not assured.

A significant portion of the Company's earnings in 2000 was derived from the Company's wholesale power trading operations which benefited from the strong demand and high wholesale prices in the Western United States. These market conditions were primarily driven by the electric power supply shortages in the Western United States. As a result of the supply imbalance, the wholesale power market in the Western United States has become extremely volatile and, while providing many marketing opportunities, presents significant risk to companies selling power into this marketplace.

During 2000, regional wholesale electricity prices reached over $1,000 per MWh mainly due to the electric power shortages in the West. Two of California's major utilities, Southern California Edison Company ("SCE") and Pacific Gas and Electric Company ("PG&E"), were unable to pass this cost on to their ratepayers. As a result, both utilities are experiencing severe liquidity constraints and have each stated publicly that they may file for bankruptcy. In response to the financial difficulties being experienced by SCE and PG&E and the resulting turmoil in the California market, the U.S. Secretary of Energy imposed a "soft" price cap of $150 per MWh effective January 1, 2001, and expiring January 23, 2001. This price cap was subsequently extended to February 7, 2001. The price cap requires that any wholesale sales of electricity into the California market be capped at $150 MWh unless the seller can demonstrate that its costs exceed the cap. In addition, the Governor and legislature of California are considering a number of proposals which may put downward pressure on the price of electricity including, but not limited to, a restructured power auction system and the purchase of power by the state on a long-term basis. It is unclear what effect these measures will have on the price of electricity in California and the surrounding states. Such measures may have an impact on the sustainability of the high electric power prices experienced in 2000.

The Company is not a major participant in the California market. In 2000, approximately seven percent of all wholesale power sales by the Company's were made directly to the California Power Exchange ("California PX"), which was the main market for the purchase and sale of electricity in the state during 2000 and the beginning of 2001 or the California Independent System Operator ("California ISO"), which manages the state's electricity transmission network. At December 31, 2000, amounts due from the California PX or ISO for power sold to them totaled $10.5 million. In January and February 2001, SCE and PG&E, major purchasers of power from the California PX and ISO, defaulted on payments due the California PX for power purchased from the PX in 2000. In addition, these companies defaulted on various debt obligations in January and February 2001 due third party creditors. The impact of these defaults on the Company was immaterial.

However, under the terms of the participation agreement with the California PX, defaults by the PX's debtors are charged-back proportionally to the creditors based on their level of participation in the exchange in the three months preceding the respective default. Through February 8, 2001, the PX has had defaults of $865 million by SCE and PG&E for power purchased in November 2000. Additional defaults may occur. The Company has been invoiced for $2.3 million as its proportionate share under the participation agreement. A number of power marketers and generators have filed a complaint with the FERC to halt the PX's attempt to collect these payments under the charge-back mechanism, claiming the mechanism was not intended for these purposes, and even if it was so intended, such an application is unreasonable and destabilizing to the California power market. If the FERC does not intercede, and the participating creditors do not make payments, the PX may draw upon letters of credit and other collateral on deposit with the exchange. The Company has issued the PX a letter of credit of $3 million. The Company does not believe the charge-back is appropriate and is evaluating its course of action; however, the Company does not believe the situation will have a material adverse effect on its results of operations or financial condition.

In addition to sales to the California PX and ISO, the Company sells power to customers in other jurisdictions who sell to the California PX and ISO and whose ability to pay may be dependent on payment from California. The Company is unable to determine whether its non-California power sales ultimately are resold in the California market. The Company's credit risk is monitored by its Risk Management Committee, which is comprised of senior finance and operations managers. The Company seeks to minimize its exposure through established credit limits, a diversified customer base and the structuring of transactions to take advantage of off-setting positions with its customers. To the extent these customers who sell power into California are dependent on payment from California to make their payments to the Company, the Company may be exposed to credit risk which did not exist prior to the California situation.

In 2000, in response to the increased credit risk and market price volatility described above, the Company recognized $8.5 million of losses to reflect management's estimate of the increased risk in the wholesale power market and its impact on 2000 revenues. This determination was based on a methodology that considers the credit ratings of its customers and the price volatility in the marketplace, among other things. The Company will continue to monitor the wholesale power marketplace and adjust its estimates accordingly.

The California Public Utilities Commission ("CPUC") has commenced an investigation into the functioning of the California wholesale power market and its associated impact on retail rates. The Company, along with other power suppliers in California, has been served with a subpoena in connection with this investigation and has responded to the subpoena. The Company has not heard further from the CPUC. The Company has been advised that the California Attorney General is conducting an investigation into possibly unlawful, unfair or anti-competitive behavior affecting electricity rates in California, and that Company documents will be subpoenaed in the near future in connection with this investigation. However, no such subpoena has yet been forthcoming.

In addition, there are several class action lawsuits that have been filed in California against generators and wholesale sellers of energy into the California market. These actions allege, in essence, that the defendants engaged in unlawful and unfair business practices to manipulate the wholesale energy market, fix prices and restrain supply, and thereby drive up prices. The Company is not a named defendant in any of these actions, and there has been no claim or threat of litigation against the Company arising out of the matters addressed in these actions.

The Company does not believe that these matters will have a material adverse effect on its results of operations or financial position.

As discussed above, SCE has defaulted on certain of its obligations and has publicly announced that it may declare bankruptcy. SCE is a 15.8% participant in PVNGS and a 48.0% participant in Four Corners. Pursuant to an agreement among the participants in PVNGS and an agreement among the participants in Four Corners Units 4 and 5, each participant is required to fund its proportionate share of operation and maintenance, capital, and fuel costs of PVNGS and Four Corners Units 4 and 5. The Company estimates SCE's total monthly share of these costs to be approximately $7.1 million for PVNGS and $8.0 million for Four Corners. The agreements provide 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 for a period of six months. During this time the defaulting participant is entitled to its share of the power generated by the respective station. After this grace period, the defaulting participant must make its payments in arrears before it is entitled to its continuing share of power. As of February 1, 2001, SCE has not defaulted on its payment obligations with respect to PVNGS and Four Corners. The Company is unable to predict whether the California situation will cause SCE to default on its payment obligations.

On November 30, 1998, the Company implemented a new customer billing system. Due to a significant number of problems associated with the implementation of the new billing system, the Company was unable to generate appropriate bills for all its customers through the first quarter of 1999 and was unable to analyze delinquent accounts until November 1999.

Under PRC rules and PRC approved Company rules, the Company is required to issue customer bills on a monthly basis. The Company was granted a temporary variance, and the PRC began a hearing on whether the Company violated PRC rules, regulations or orders or the New Mexico Public Utility Act. The investigation was concluded on November 2, 1999, without the PRC imposing any civil penalty on the Company and with an approved stipulation that the Company be permitted to bill an additional service charge to customers who were not billed the appropriate electric service charge or gas access fee. The stipulation was limited to approximately $0.7 million in the November and December billing cycles.

Because of the implementation issues associated with the new billing system, the Company estimated retail gas and electric revenues through July 1999. Beginning with August 1999, the Company was able to determine actual revenues for all prior periods affected and began reconciling with previously estimated revenues. In December 1999, the Company completed its reconciliation of system revenues. As a result, 1999 revenues represented actual revenues as determined by the new billing system. The resulting reconciliation did not materially impact recorded revenues. However, a significant number of individual accounts required corrections.

As a result of the delay of normal collection activities, the Company incurred a significant increase in delinquent accounts, many of which occurred with customers that no longer have active accounts with the Company. As a result, the Company significantly increased its estimate of bad debt costs throughout 1999.

The Company continued its analysis and collection efforts of its delinquent accounts resulting from the problems associated with the implementation of the new customer billing system throughout 2000 and identified additional bad debt exposure. By the end of 2000, the Company completed its analysis of its delinquent accounts and resumed its normal collection procedures. As a result, the Company has determined that $13.5 million of customer receivables will not be collectible. Based upon information available at December 31, 2000, the Company believes the allowance for doubtful accounts of $9.0 million is adequate for management's estimate of potential uncollectible accounts.

In addition, due to the significantly higher natural gas prices experienced in November and December 2000, the Company increased its bad debt expense by approximately $2 million in anticipation of higher than normal delinquency rates. The Company expects this trend to continue as long as natural gas prices remain higher than in the past years.

The following is a summary of the allowance for doubtful accounts during 2000, 1999 and 1998:

(In thousands)	2000	1999	1998
Allowance for doubtful accounts, beginning of year	$ 12,504	$ 836	$ 783
Bad debt expense	9,980	11,496	3,325
Less: Write off (adjustments) of uncollectible accounts	13,521	(172)	3,272
Allowance for doubtful accounts, end of year	$ 8,963	$ 12,504	$ 836

In November 1998, the NMPUC issued a final order in the Company's electric rate case, requiring the Company to reduce rates in 1999 by $60.2 million, by $25.6 million in 2000 and by an additional $25.6 million in 2001. The rate reduction order reflected, among other things, the revaluation of the Company's generation resources based on a so-called "market-based price" and the finding by the NMPUC that recovery of stranded costs is illegal. In December 1998, the Company appealed the rate case order to the New Mexico Supreme Court ("Supreme Court").

On March 15, 1999, the Supreme Court issued a ruling, vacating the NMPUC order on the Company's electric rate case and remanding the case to the PRC, the successor of the NMPUC, for further proceedings.

On August 25, 1999, the PRC issued an order approving a settlement. The PRC ordered the Company to reduce its electric rates by $34.0 million retroactive to July 30, 1999. In addition, the order includes a rate freeze until retail electric competition is fully implemented in New Mexico or until January 1, 2003 whichever is earlier. The settlement reduce electric distribution operating revenues by approximately $39 million and $19 million in 2000 and 1999, respectively.

In April 2000, the Supreme Court ruled in favor of the Company in overturning a $6.9 million rate reduction imposed on the Company's natural gas utility by the state's former NMPUC in 1997 for its 1995 gas rate case. Although the Supreme Court upheld certain portions of the gas rate case order by the NMPUC, the Supreme Court vacated the rate order as "unreasonable and unlawful" because certain disallowances ordered by the NMPUC unreasonably hindered the Company's ability to earn a fair rate of return. The case was remanded to the PRC. In addition in March 2000, the Supreme Court vacated the NMPUC's final order in the Company's 1997 gas rate case and remanded it back to the PRC. The Supreme Court specifically rejected portions of the final order requiring the Company to offer residential customers a choice of utility access fees.

On October 24, 2000, the PRC issued a final order approving a stipulation negotiated in the third quarter between the Company and the PRC staff which resolved all issues raised by the two remanded rate cases. The final order adds approximately $1.2 million to the Company's revenues in the final quarter of 2000, $4.7 million in 2001, and $3.9 million in 2002. The Company has reversed certain reserves against costs recovered in the settlement that were recorded against earnings at the time of the original regulatory orders, resulting in a one-time pre-tax gain of $4.6 million. This amount will be collected from customers in rates over the next 12 years.

In 1998, the Company and the trustee of the Company's master decommissioning trust filed a civil complaint and an amended complaint, respectively, against several companies and individuals for the under-performance of a corporate owned life insurance program. The program was used to fund a portion of the Company's nuclear decommissioning obligations for its 10.2% interest in PVNGS.

The parties reached a settlement agreement under which the complaint and counterclaim were dismissed with prejudice on September 5, 2000 and the Company and trustee received $13.8 million in settlement proceeds.

The Company's 100 MW power sale contract with San Diego Gas and Electric Company ("SDG&E") will expire in April of 2001. SDG&E has verbally notified the Company that it will not renew this contract. The FERC must ultimately approve the termination of the contract. The Company currently estimates that the net revenue reduction resulting from the expiration of the SDG&E contract will be approximately $20 million annually. Whether or not these revenues will be replaced depends on market conditions. In addition, previously reported litigation between the Company and SDG&E regarding prior years' contract pricing has been resolved in the Company's favor.

On October 4, 1999, Western Area Power Administration ("WAPA") filed a petition at the FERC requesting the FERC, on an expedited basis, to order the Company to provide network transmission service to WAPA under the Company's Open Access Transmission Tariff on behalf of the DOE as contracting agent for Kirtland Air Force Base ("KAFB"). The Company is opposing the WAPA petition and intends to litigate this matter vigorously. The net revenue reduction to the Company if the DOE replaces the Company as the power supplier to KAFB is estimated to be approximately $7.0 million annually. Whether or not these revenues will be replaced depends on market conditions.

As part of the rate case settlement (discussed above), the Company agreed that certain changes to the language of the retail tariff under which KAFB currently takes service would be considered in a separate proceeding before the PRC. Hearings on this issue have not yet been scheduled. The PRC is considering briefs submitted by the parties addressing the scope of the proceeding. KAFB has not renewed its electric service contract with the Company that expired in December 1999 but continues to purchase retail service from the Company.

In 1997, the Company was notified by San Juan Coal Company ("SJCC"), supplier of coal to SJGS, of certain audit exceptions identified by the Federal Minerals Management Service ("MMS") for the period 1986 through 1997. These exceptions pertain to the valuation of coal for purposes of calculating the Federal coal royalty. Primary issues include whether coal processing and transportation costs should be included in the base value of La Plata coal for royalty determination. The Company was notified during the fourth quarter of 2000 that SJCC and the MMS agreed to a settlement of all claims. The Company's share of the settlement including a recalculation of current invoices was approximately $3 million. The Company recorded the settlement as part of its cost of coal in the fourth quarter of 2000.

In 1996, the Company was notified by SJCC that the Navajo Nation proposed to select certain properties within the San Juan and La Plata Mines (the "mining properties") pursuant to the Navajo-Hopi Land Settlement Act of 1974 (the "Act"). The mining properties are operated by SJCC under leases from the Bureau of Land Management ("BLM") and comprise a portion of the fuel supply for the SJGS. An administrative appeal by SJCC is pending. In the appeal, SJCC argued that transfer of the mining properties to the Navajo Nation may subject the mining operations to taxation and additional regulation by the Navajo Nation, both of which could increase the price of coal that might potentially be passed on to the SJGS through the existing coal sales agreement. The Company is monitoring the appeal and other developments on this issue and will continue to assess potential impacts to the SJGS and the Company's operations. The Company is unable to predict the ultimate outcome of this matter.

The Company's generation mix for 2000 was 68.0% coal, 39.8% nuclear and 2.2% gas and oil. Due to locally available natural gas and oil supplies, the utilization of locally available coal deposits and the generally abundant supply of nuclear fuel, the Company believes that adequate sources of fuel are available for its generating stations (see "Coal Fuel Supply" above).

Water for Four Corners and SJGS is obtained from the San Juan River. BHP Minerals International, Inc. ("BHP") holds rights to San Juan River water and has committed a portion of those rights to Four Corners through the life of the project. The Company and Tucson Electric Power Company ("Tuscon") have a contract with the United States Bureau of Reclamation ("USBR") for consumption of 16,200 acre feet of water per year for the SJGS. The contract expires in 2005. In addition, the Company was granted the authority to consume 8,000 acre feet of water per year under a state permit that is held by BHP. The Company is of the opinion that sufficient water is under contract for the SJGS through 2005. The Company has signed a contract with the Jicarilla Apache Tribe for a twenty-seven year term, beginning in 2006, for replacement of the current USBR contract for 16,200 acre feet of water. The contract must still be approved by the USBR and is also subject to environmental approvals. The Company is actively involved in the San Juan River Recovery Implementation Program to mitigate any concerns with the taking of the negotiated water supply from a river that contains endangered species and critical habitat. The Company believes that it will continue to have adequate sources of water available for its generating stations.

The Company obtains its supply of natural gas primarily from sources within New Mexico pursuant to contracts with producers and marketers. These contracts are generally sufficient to meet the Company's peak-day demand. The Company serves certain cities which depend on El Paso Natural Gas ("EPNG") or Transwestern Pipeline Company for transportation of gas supplies. Because these cities are not directly connected to the Company's transmission facilities, gas transported by these companies is the sole supply source for those cities. The Company believes that adequate sources of gas are available for its distribution systems.

The United States Environmental Protection Agency ("EPA") has proposed changes to its New Source Review ("NSR") rules that could result in many actions at power plants that have previously been considered routine repair and maintenance activities (and hence not subject to the application of NSR requirements) as now being subject to NSR. In November 1999, the Department of Justice at the request of the EPA filed complaints against seven companies alleging the companies over the past 25 years had made modifications to their plants in violation of the NSR requirements, and in some cases the New Source Performance Standards

("NSPS") regulations. Whether or not the EPA will prevail is unclear at this time. The EPA has reached a settlement with one of the companies sued by the Justice Department and is in the process of attempting to negotiate settlement agreements with one of those other companies. No complaint has been filed against the Company, and the Company believes that all of the routine maintenance, repair, and replacement work undertaken at its power plants was and continues to be in accordance with the requirements of NSR and NSPS. However, by letter dated October 23, 2000, the New Mexico Environment Department ("NMED") made an information request of the Company, advising the Company that the NMED was in the process of assisting the EPA in the EPA's nationwide effort "of verifying that changes made at the country's utilities have not inadvertently triggered a modification under the Clean Air Act's Prevention of Significant Determination ("PSD") policies." The Company has responded to the NMED information request.

The nature and cost of the impacts of EPA's changed interpretation of the application of the NSR and NSPS, together with proposed changes to these regulations, may be significant to the power production industry. However, the Company cannot quantify these impacts with regard to its power plants. It is also unknown what changes in EPA policy, if any, may occur in the NSR area as a result of the change in administration in Washington. If the EPA should prevail with its current interpretation of the NSR and NSPS rules, the Company may be required to make significant capital expenditures which could have a material adverse affect on the Company's financial position and results of operations.

The normal course of operations of the Company necessarily involves activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and in some instances may be imposed without regard to fault, or may be imposed for past acts, even though such past acts may have been lawful at the time they occurred. Sources of potential environmental liabilities include the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980 and other similar statutes.

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company 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, the Company records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

The Company's recorded estimated minimum liability to remediate its identified sites is $8.3 million. The ultimate cost to clean up the Company'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; and the time periods over which site remediation is expected to occur. The Company believes that, due to these uncertainties, it is remotely possible that cleanup costs could exceed its recorded liability by up to $21.1 million. The upper limit of this range of costs was estimated using assumptions least favorable to the Company.

The collective bargaining agreement between the Company and the International Brotherhood of Electrical Workers Local Union 611 ("IBEW") which covers the approximately 654 bargaining unit employees in the Utility and Generation and Trading Operations expired on May 1, 2000, but continued in full force and effect while the parties negotiated. The successor agreement was reached on August 22, 2000 and was ratified by IBEW members on September 1, 2000. The IBEW's charge with the National Labor Relations Board ("NLRB") alleging the Company has bargained in bad faith, and by its actions has committed an unfair labor practice is pending. The Company will vigorously defend against the Union's allegations.

Arizona Public Service Company ("APS"), the operating agent for Four Corners, has informed the Company that in March 1999, APS initiated discussions with the Navajo Nation regarding various tax issues in conjunction with the expiration of a tax waiver, in July 2001, which was granted by the Navajo Nation in 1985. The tax waiver pertains to the possessory interest tax and the business activity tax associated with the Four Corners operations on the reservation. The Company believes that the resolution of these tax issues will require an extended process and could potentially affect the cost of conducting business activities on the reservation. The Company is unable to predict the ultimate outcome of discussions with the Navajo Nation regarding these tax issues.

DECOMMISSIONING:

The Staff of the SEC has questioned certain of the current accounting practices of the electric industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in financial statements of electric utilities. In February 2000, the Financial Accounting Standards Board ("FASB") issued an exposure draft regarding Accounting for Obligations Associated with the Retirement of Long-Lived Assets ("Exposure Draft"). The Exposure Draft requires the recognition of a liability for an asset retirement obligation at fair value. In addition, present value techniques used to calculate the liability must use a credit adjusted risk-free rate. Subsequent remeasures of the liability would be recognized using an allocation approach. The Company has not yet determined the impact of the Exposure Draft.

STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 133, *ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES*, ("SFAS 133"):

SFAS 133 establishes accounting and reporting standards requiring derivative instruments to be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 also requires that changes in the derivatives' fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. In June 1999, FASB issued SFAS 137 to amend the effective date for the compliance of SFAS 133 to January 1, 2001. In June 2000, the FASB issued SFAS 138 that provides certain amendments to SFAS 133. The amendments, among other things, expand the normal sales and purchases exception to contracts that implicitly or explicitly permit net settlement and contracts that have a market mechanism to facilitate net settlement. The expanded exception excludes a significant portion of the Company's contracts that previously would have required valuation under SFAS 133. Effective January 1, 2001, the Company adopted SFAS 133, as amended.

The Company has identified all financial instruments that meet the definition of a derivative under SFAS 133, as amended, as of January 1, 2001 in which the Company is a party. Certain of the Company's identified derivative instruments are marked-to-market under EITF 98-10 as of December 31, 2000. The related gains and losses (unrealized and realized) for these derivative instruments are recorded as adjustments to operating revenues. In addition, the financial instruments underlying the Company's corporate hedge of certain investments in its nuclear, executive retirement and retiree medical benefits trusts meet the definition of a derivative under SFAS 133, as amended, and are marked-to-market as of December 31, 2000. The related unrealized and realized losses are recorded as a component of other income and deductions on the Consolidated Statement of Earnings.

Pursuant to SFAS 133, as amended, the Company designated certain forward purchase contracts for electricity as cash flow hedges. The Company's designated cash flow hedges at January 1, 2001, were forward purchase contracts for the purchase of electric power for forecasted jurisdictional use during planned outages in 2001. The hedged risks associated with these instruments are the changes in cash flows associated with the forecasted purchase of electricity due to changes in the price of electricity on the spot market. Assessment of hedge effectiveness will be based on the changes in the forward price of electricity.

SFAS 133, as amended, provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The results of hedge ineffectiveness and the change in fair value of a derivative that an entity has chosen to exclude from hedge effectiveness are required to be presented in current earnings.

Because the Company's derivative instruments as defined by SFAS 133, as amended, are currently marked-to-market or are classified as cash flow hedges, the adoption of SFAS 133, as amended, will not have an impact on the net earnings of the Company. However, the adoption of SFAS 133, as amended, will increase comprehensive income by $6.0 million, net of taxes for the recording of the Company's cash flow hedges. The physical contracts will subsequently be recognized as a component of the cost of purchased power when the actual physical delivery occurs. At January 1, 2001, the derivative instruments designated as cash flow hedges had a gross asset position of $9.9 million on the hedged transactions. See Note 5 for financial instruments currently marked-to-market.

Statements made in this filing that relate to future events are made pursuant to the Private Securities Litigation Reform Act of 1995. Readers are cautioned that such forward-looking statements with respect to revenues, earnings, performance, strategies, prospects and other aspects of the business of the Company are based upon current expectations and are subject to risk and uncertainties, as are the forward-looking statements with respect to the benefits of the Company's proposed acquisition of Western Resources and the businesses of the Company and Western Resources. The Company assumes no obligation to update this information.

Because actual results may differ materially from expectations, the Company cautions readers not to place undue reliance on these statements. A number of factors, including weather, fuel costs, changes in supply and demand in the market for electric power, the performance of generating units and transmission system, and state and federal regulatory and legislative decisions and actions, including rulings issued by the PRC pursuant to the Electric Utility Industry Restructuring Act of 1999 and in other cases now pending or which may be brought before the commission and any action by the New Mexico Legislature to amend or repeal that Act, or other actions relating to restructuring or stranded cost recovery, or federal or state regulatory, legislative or legal action connected with the California wholesale power market, could cause the Company's results or outcomes to differ materially from those indicated by such forward-looking statements in this filing.

In addition, factors that could cause actual results or outcomes related to the proposed acquisition of Western Resources to differ materially from those indicated by such forward-looking statements include, but are not limited to, risks and uncertainties relating to: the possibility that shareholders of the Company and/or Western Resources will not approve the transaction, the risks that the businesses will not be integrated successfully, the risk that the benefits of the transaction may not be fully realized or may take longer to realize than expected, disruption from the transaction making it more difficult to maintain relationships with clients, employees, suppliers or other third parties, conditions in the financial markets relevant to the proposed transaction, the receipt of regulatory and other approvals of the transaction, that future circumstances could cause business decisions or accounting treatment to be decided differently than now intended, changes in laws or regulations, changing governmental policies and regulatory actions with respect to allowed rates of return on equity and equity ratio limits, industry and rate structure, stranded cost recovery, operation of nuclear power facilities, acquisition, disposal, depreciation and amortization of assets and facilities, operation and construction of plant facilities, recovery of fuel and purchased power costs, decommissioning costs, present or prospective wholesale and retail competition (including retail wheeling and transmission costs), political and economic risks, changes in and compliance with environmental and safety laws and policies, weather conditions (including natural disasters such as tornadoes), population growth rates and demographic patterns, competition for retail and wholesale customers, availability, pricing and transportation of fuel and other energy commodities, market demand for energy from plants or facilities, changes in tax rates or policies or in rates of inflation or in accounting standards, unanticipated delays or changes in costs for capital projects, unanticipated changes in operating expenses and capital expenditures, capital market conditions, competition for new energy development opportunities and legal and administrative proceedings (whether civil, such as environmental, or criminal) and settlements, the outcome of Protection One accounting issues reviewed by the SEC staff as disclosed in previous Western Resources SEC filings, and the impact of Protection One's financial condition on Western Resources' consolidated results.

QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electric prices and also adverse market changes for investments held by the Company's various trusts. The Company also uses certain derivative instruments for bulk power electricity trading purposes in order to take advantage of favorable price movements and market timing activities in the wholesale power markets. Information about market risk is set forth in Note 5 to the Notes to the Consolidated Financial Statements and incorporated by reference. The following additional information is provided.

The Company uses value at risk ("VAR") to quantify the potential exposure to market movement on its open contracts and excess generating assets. The VAR is calculated utilizing the variance/co-variance methodology over a three day period within a 99% confidence level. The Company's VAR as of December 31, 2000 from its electric trading contracts was $36.9 million. In 2000, the Company changed its methodology for calculating its VAR. Previously, bulk power available for sale from the Company's excess capacity and assets excluded from jurisdictional rates was measured using projected hourly load forecasts. These assets are now measured using average peak load forecasts for the respective block of power in the forward market. The change in methodology results in less available MW's for sale in the VAR calculation. Management believes this more accurately portrays its capacity from its excess generating assets.

The Company's wholesale power marketing operations, including both firm commitments and trading activities, are managed through an asset backed strategy, whereby the Company's aggregate net open position is covered by its own excess generation capabilities. The Company is exposed to market risk if its generation capabilities were disrupted or if its jurisdictional load requirements were greater than anticipated. If the Company were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases. The Company's VAR calculation considers this exposure.

The Company's VAR is regularly monitored by the Company's Risk Management Committee which is comprised of senior finance and operations managers. The Risk Management Committee has put in place procedures to ensure that increases in VAR are reviewed and, if deemed necessary, acted upon to reduce exposures. In addition, the Company is exposed to credit losses in the event of non-performance or non-payment by counterparties. The Company uses a credit management process to access and monitor the financial conditions of counterparties. Credit exposure is also regularly monitored by the Company's Risk Management committee.

The VAR represents an estimate of the potential gains or losses that could be recognized on the Company's wholesale power marketing portfolio given current volatility in the market, and is not necessarily indicative of actual results that may occur, since actual future gains and losses will differ from those estimated. Actual gains and losses may differ due to actual fluctuations in market rates, operating exposures, and the timing thereof, as well as changes to the Company's wholesale power marketing portfolio during the year.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The accompanying financial statements, which consolidate the accounts of Public Service Company of New Mexico and its subsidiaries, have been prepared in conformity with accounting principles generally accepted in the United States.

The integrity and objectivity of data in these financial statements and accompanying notes, including estimates and judgments related to matters not concluded by year-end, are the responsibility of management as is all other information in this Annual Report. Management devotes ongoing attention to review and appraisal of its system of internal controls. This system is designed to provide reasonable assurance, at an appropriate cost, that the Company's assets are protected, that transactions and events are recorded properly and that financial reports are reliable. The system is augmented by a staff of corporate auditors; careful attention to selection and development of qualified financial personnel; and programs to further timely communication and monitoring of policies, standards and delegated authorities.

The Audit Committee of the Board of Directors, composed entirely of outside directors, meets regularly with financial management, the corporate auditors and the independent auditors to review the work of each. The independent auditors and corporate auditors have free access to the Audit Committee, without management representatives present, to discuss the results of their audits and their comments on the adequacy of internal controls and the quality of financial reporting.

To the Board of Directors and Stockholders of
Public Service Company of New Mexico:

We have audited the accompanying consolidated balance sheets and statements of capitalization of Public Service Company of New Mexico (a New Mexico Corporation) and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of earnings and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. 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 Public Service Company of New Mexico and subsidiaries as of December 31, 2000 and 1999, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2000 in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

Albuquerque, New Mexico
January 26, 2001

(In thousands, except per share amounts)	Year Ended December 31		
	2000	1999	1998
Operating Revenues: (notes 1, 7)			
Utility	$ 859,389	$ 778,286	$ 812,250
Generation and Trading	1,075,178	689,981	642,358
Unregulated businesses	2,158	8,855	1,266
Intersegment elimination	(325,451)	(319,579)	(363,429)
Total operating revenues	1,611,274	1,157,543	1,092,445
Operating Expenses:			
Cost of energy sold	949,880	531,952	449,426
Administrative and general	147,268	153,709	135,727
Energy production costs	139,894	140,784	149,747
Depreciation and amortization	93,059	92,661	86,141
Transmission and distribution costs	60,330	59,264	56,457
Taxes, other than income taxes	34,405	34,084	37,992
Income taxes (note 7)	53,964	25,010	41,306
Total operating expenses	1,478,800	1,037,464	956,796
Operating income	132,474	120,079	135,649
Other Income and Deductions:			
Other	54,296	47,500	37,672
Income tax expense (note 7)	(20,382)	(17,298)	(14,985)
Net other income and deductions	33,914	30,202	22,687
Income before interest charges	166,388	150,281	158,336
Interest Charges:			
Interest on long-term debt (note 3)	62,823	65,899	50,929
Other interest charges	2,619	4,768	12,288
Net interest charges	65,442	70,667	63,217
Net Earnings from Continuing Operations	100,946	79,614	95,119
Discontinued Operations, Net of Tax (note 13)	—	—	(12,437)
Cumulative Effect of a Change in Accounting Principle, Net of Tax	—	3,541	—
Net Earnings	100,946	83,155	82,682
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 100,360	$ 82,569	$ 82,096
Net Earnings per Share of Common Stock (Basic) (note 6)	$ 2.54	$ 2.01	$ 1.97
Net Earnings per Share of Common Stock (Diluted) (note 6)	$ 2.53	$ 2.01	$ 1.95
Dividends Paid per Share of Common Stock	$ 0.80	$ 0.80	$ 0.77

The accompanying notes are an integral part of these financial statements.

(In thousands)	Year Ended December 31	
	2000	**1999**
Utility Plant, at original cost except PVNGS: (notes 10, 11)		
Electric plant in service	$ 2,030,813	$ 1,976,009
Gas plant in service	553,755	483,819
Common plant in service and plant held for future use	36,678	69,273
	2,621,246	2,529,101
Less accumulated depreciation and amortization	1,153,377	1,077,576
	1,467,869	1,451,525
Construction work in progress	123,653	104,934
Nuclear fuel, net of accumulated amortization of $19,081 and $20,832	25,784	25,923
Net utility plant	1,617,306	1,582,382
Other Property and Investments:		
Other investments (notes 5, 12)	479,821	483,008
Non-utility property, net of accumulated depreciation of $1,644 and $1,261	3,666	4,439
Total other property and investments	483,487	487,447
Current Assets:		
Cash and cash equivalents	107,691	120,399
Accounts receivables, net of allowance for uncollectible accounts of $8,963 and $12,504	242,742	147,746
Other receivables	64,857	68,911
Inventories	36,091	39,992
Regulatory assets (note 2)	47,604	24,056
Other current assets	11,417	4,934
Total current assets	510,402	406,038
Deferred charges:		
Regulatory assets (note 2)	226,849	195,898
Prepaid pension cost (note 8)	18,116	16,126
Other deferred charges	38,073	35,377
Total deferred charges	283,038	247,401
	$ 2,894,233	$ 2,723,268

The accompanying notes are an integral part of these financial statements.

(In thousands)	Year Ended December 31	
	2000	**1999**
Capitalization: (note 3)		
Common stock equity:		
Common stock outstanding—39,118 and 40,703 shares	$ 195,589	$ 203,517
Additional paid-in capital	432,222	453,393
Accumulated other comprehensive income, net of tax (note 3)	(27)	2,352
Retained earnings	296,843	227,829
Total common stock equity	924,627	887,091
Minority interest	12,211	12,771
Cumulative preferred stock without mandatory redemption requirements	12,800	12,800
Long-term debt, less current maturities (note 3)	953,823	988,489
Total capitalization	1,903,461	1,901,151
Current Liabilities:		
Accounts payable	257,991	150,645
Accrued interest and taxes	36,889	34,237
Other current liabilities	67,758	54,137
Total current liabilities	362,638	239,019
Deferred Credits:		
Accumulated deferred income taxes (note 7)	166,249	153,179
Accumulated deferred investment tax credits (note 7)	47,853	50,996
Regulatory liabilities (note 2)	65,552	88,497
Regulatory liabilities related to accumulated deferred income tax (note 2)	20,696	15,091
Accrued postretirement benefits cost (note 8)	11,899	8,945
Other deferred credits (note 12)	315,885	266,390
Total deferred credits	628,134	583,098
Commitments and Contingencies (note 11)	—	—
	$ 2,894,233	$ 2,723,268

The accompanying notes are an integral part of these financial statements.

(In thousands)	Year Ended December 31		
	2000	1999	1998
Cash Flows From Operating Activities:			
Net earnings	$ 100,946	$ 83,155	$ 82,682
Adjustments to reconcile net earnings to net cash flows from operating activities:			
Depreciation and amortization	103,829	103,891	98,154
Gain on cumulative effect of a change in Accounting principle	—	(5,862)	—
Other	33,268	26,170	27,462
Changes in certain assets and liabilities:			
Accounts receivables	(94,996)	(16,937)	1,302
Other assets	(32,444)	(20,189)	31,066
Accounts payable	107,346	36,670	(40,490)
Other liabilities	21,566	6,147	10,812
Net cash flows provided from operating activities	239,515	213,045	210,988
Cash Flows From Investing Activities:			
Utility plant additions	(146,878)	(95,298)	(128,784)
Return (purchase) of PVNGS lease obligation bonds	16,668	16,903	(204,364)
Merger acquisition costs	(6,700)	—	—
Other investing	(20,590)	22,509	(7,844)
Net cash flows used in investing activities	(157,500)	(55,886)	(340,992)
Cash Flows From Financing Activities:			
Borrowings (note 3)	—	11,500	896,348
Repayments (note 3)	(32,800)	(58,200)	(694,651)
Exercise of employee stock options (note 9)	(1,232)	1,453	(3,687)
Common stock repurchase (note 3)	(27,867)	(18,799)	—
Dividends paid	(32,265)	(33,359)	(32,789)
Other Financing	(559)	(635)	7,868
Net cash flows generated (used) by financing activities	(94,723)	(98,040)	173,089
Increase (Decrease) in Cash and Cash Equivalents	(12,708)	59,119	43,085
Beginning of Year	120,399	61,280	18,195
End of Year	$ 107,691	$ 120,399	$ 61,280
Supplemental cash flow disclosures:			
Interest paid	$ 64,045	$ 67,770	$ 50,109
Income taxes paid, net of refunds	$ 50,480	$ 36,575	$ 49,048
Acquired DOE pipeline in exchange for transportation services	—	$ 3,100	—

The accompanying notes are an integral part of these financial statements.

(In thousands)	Year Ended December 31	
	2000	**1999**
Common Stock Equity: (note 3)		
Common Stock, par value $5 per share	$ 195,589	$ 203,517
Additional paid-in capital	432,222	453,393
Accumulated other comprehensive income, net of tax	(27)	2,352
Retained earnings	296,843	227,829
Total common stock equity	924,627	887,091
Minority Interest	12,211	12,771
Cumulative Preferred Stock: (note 3)		
Without mandatory redemption requirements:		
1965 Series, 4.58% with a stated value of $100.00 and a current redemption price of $102.00. Outstanding shares at December 31, 2000 were 128,000	12,800	12,800
Long-Term Debt: (note 3)		
Issue and Final Maturity		
First Mortgage Bonds, Pollution Control Revenue Bonds:		
5.7% due 2016	65,000	65,000
6.375% due 2022	46,000	46,000
Total First Mortgage Bonds	111,000	111,000
Senior Unsecured Notes, Pollution Control Revenue Bonds:		
6.30% due 2016	77,045	77,045
5.75% due 2022	37,300	37,300
5.80% due 2022	100,000	100,000
6.375% due 2022	90,000	90,000
6.375% due 2023	36,000	36,000
6.40% due 2023	100,000	100,000
6.30% due 2026	23,000	23,000
6.60% due 2029	11,500	11,500
Total Senior Unsecured Notes, Pollution Control Revenue Bonds	474,845	474,845
Senior Unsecured Notes:		
7.10% due 2005	268,420	268,420
7.50% due 2018	100,025	135,000
Other, including unamortized premium and (discounted), net	(467)	(776)
Total long-term debt	953,823	988,489
Total Capitalization	$ 1,903,461	$ 1,901,151

The accompanying notes are an integral part of these financial statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2000, 1999, AND 1998

ACCOUNTING PRINCIPLES

The Company prepares its financial statements in accordance with the uniform system of accounts prescribed by the Federal Energy Regulatory Commission ("FERC") and the National Association of Regulatory Utility Commissioners, and adopted by the New Mexico Public Regulation Commission ("PRC"), the successor of the New Mexico Public Utility Commission ("NMPUC"), effective January 1, 1999.

The Company's accounting policies conform to the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation ("SFAS 71"). SFAS 71 requires a rate-regulated entity to reflect the effects of regulatory decisions in its financial statements. In accordance with SFAS 71, the Company has deferred certain costs and recorded certain liabilities pursuant to the rate actions of the PRC, NMPUC and FERC. These "regulatory assets" and "regulatory liabilities" are enumerated and discussed in Note 2.

To the extent that the Company concludes that the recovery of a regulatory asset is no longer probable due to regulatory treatment, the effects of competition or other factors, the amount would be recorded as a charge to earnings as recovery is no longer probable. The Company has discontinued the application of SFAS 71 as of December 31, 1999, for the generation portion of its business effective with the passage of the Electric Utility Industry Restructuring Act of 1999 ("Restructuring Act") in accordance with Financial Accounting Standards No. 101, "Accounting for the Discontinuation of Application of Financial Accounting Standards Board ("FASB") Statement No. 71". The Company evaluates its regulatory assets under Financial Accounting No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of" ("FAS 121"). In 2000, the Company determined certain stranded assets would not be recovered and recorded a charge to earnings for these amounts. The Company believes that it will recover costs associated with its remaining stranded assets including asset closure costs through a non-bypassable charge as permitted by the Restructuring Act. See Note 2 for additional discussion.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of the Company and subsidiaries in which it owns a majority voting interest. All significant intercompany transactions and balances have been eliminated.

FINANCIAL STATEMENT PREPARATION AND PRESENTATION

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the reported amounts of assets 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 recorded amounts could differ from those estimated.

UTILITY PLANT

Utility plant, with the exception of Palo Verde Nuclear Generating Station ("PVNGS") Unit 3 and the Company's owned interests in PVNGS Units 1 and 2, is stated at original cost, which includes capitalized payroll-related costs such as taxes, pension and other fringe benefits, administrative costs and an allowance for funds used during construction. Pursuant to a rate stipulation dated October 1993, the Company did not capitalize amounts relating to an allowance for funds used during construction in 2000, 1999 or 1998. Utility plant includes certain electric assets not subject to regulation.

It is Company policy to charge repairs and minor replacements of property to maintenance expense and to charge major replacements to utility plant. 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.

REVENUE RECOGNITION

The Company's Utility Operations record electric and gas operating revenues in the period of delivery, which includes estimated amounts for service rendered but unbilled at the end of each accounting period. Utility Operations gas operating revenues exclude an adjustment for gas purchase costs that are above levels included in base rates but are recoverable under the Purchased Gas Adjustment Clause ("PGAC") administered by the PRC. The Company recognizes this adjustment when it is permitted to bill under PRC guidelines.

summary of significant accounting policies (continued)

The Company's Generation and Trading Operations record operating revenues to the Utility Operations and to third parties in the period of delivery. Certain sales to firm requirements wholesale customers include a cost of energy adjustment for recoverable fixed costs. The Company recognizes this adjustment when it is permitted to bill under FERC guidelines. Generation and Trading Operations transactions that are net settled, whereby the unplanned netting of delivery and acceptance of electric power for convenience of transmission and settlement occurs (referred to as a "bookout"), are recorded gross in operating revenues and fuel and purchased power expense.

Financial instruments utilized in connection with energy trading activities are accounted for at fair market value under Emerging Issues Task Force ("EITF") 98-10. Unrealized gains and losses resulting from the impact of price movements on the Company's contracts are recognized as adjustments to Generation and Trading Operations operating revenues. The market prices used to value these transactions reflect management's best estimate considering various factors including closing exchange and over-the counter quotations, time value and volatility factors underlying the commitments.

The cash flow impact of these financial instruments is reflected as cash flows from operating activities in the Consolidated Statement of Cash Flows.

RECOVERABLE FUEL COSTS

The Company's fuel and purchased power costs for its firm requirements wholesale customers that are above the levels included in base rates are recoverable under a fuel and purchased power cost adjustment approved by the FERC. Such costs are deferred until the period in which they are billed or credited to customers. The Company's gas purchase costs that are above levels included in base rates are recoverable under similar Purchased Gas Adjustment Clause administered by the PRC.

DEPRECIATION AND AMORTIZATION

Provision for depreciation and amortization of utility plant is made at annual straight-line rates approved by the PRC. The average rates used are as follows:

	2000	1999	1998
Electric plant	3.42%	3.38%	3.32%
Gas plant	3.28%	3.37%	3.06%
Common plant	6.75%	7.73%	7.34%

The provision for depreciation of certain equipment is charged to clearing accounts and subsequently allocated to operating expenses or construction projects based on the use of the equipment. Depreciation of non-utility property is computed on the straight-line method. Amortization of nuclear fuel is computed based on the units of production method.

NUCLEAR DECOMMISSIONING

The Company accounts for nuclear decommissioning costs on a straight-line basis over the respective license period. Such amounts are based on the future value of expenditures estimated to be required to decommission the plant.

For gas, the excess or deficiency is accumulated for refund or surcharge to customers on an annual basis. Future recovery of these costs is subject to approval by the PRC.

AMORTIZATION OF DEBT ACQUISITION COSTS

Discount, premium and expense related to the issuance of long-term debt are amortized over the lives of the respective issues. In connection with the retirement of long-term debt, such amounts associated with resources subject to PRC regulation are amortized over the lives of the respective issues. Amounts associated with the Company's firm-requirements wholesale customers and its resources excluded from PRC retail rates are recognized immediately as expense or income as they are incurred.

STOCK OPTIONS

The Company continues to apply Accounting Principles Board ("APB") Opinion No. 25, Accounting for Stock Issued to Employees, and related interpretations in accounting for its plan. Accordingly, no compensation cost has been recognized for this plan.

INCOME TAXES

The Company reports income tax expense in accordance with SFAS 109, Accounting for Income Taxes. SFAS 109 requires that deferred income taxes for temporary differences between financial and income tax reporting be recorded using the liability method. Therefore, deferred income taxes are computed using the statutory tax rates scheduled to be in effect when temporary differences reverse. Current PRC jurisdictional rates include the tax effects of the majority of these temporary differences (normalization). Recovery of reversing temporary differences previously accounted for under the flow-through method is also included in rates charged to customers. For regulated operations, any changes in tax rates applied to accumulated deferred income taxes may not be immediately recognized because of ratemaking and tax accounting provisions required by the Internal Revenue Code. Items accorded flow-through treatment under PRC orders, deferred income taxes and the future ratemaking effects of such taxes, as well as corresponding regulatory assets and liabilities, are recorded in the financial statements.

ASSET IMPAIRMENT

The Company regularly evaluates the carrying value of its regulatory and tangible long-lived assets in relation to their future undiscounted cash flows to assess recoverability in accordance with SFAS 121, Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of. Impairment testing of power generation assets is performed periodically in response to changes in market conditions resulting from industry deregulation. Power generation assets used to supply jurisdictional and wholesale markets are evaluated on a group basis using future undiscounted cash flows based on current open market price conditions. The Company also has generation assets that are used for the sole purpose of reliability. These assets are tested as an individual group. Power generation assets held under operating leases are not currently evaluated for impairment (see note 4).

FINANCIAL INSTRUMENTS

The Company enters into energy trading contracts to take advantage of market opportunities associated with the purchase and sale of electricity. Such contracts are marked-to-market each period end. In addition, the Company protected its decommissioning and retiree trust assets against market price volatility by purchasing financial put and call options. These instruments are also marked-to-market each period end. The Company also periodically hedges natural gas purchases to limit commodity price volatility. Unrealized gains and losses from natural gas-related swaps, futures and forward contracts are deferred and recognized as the natural gas is sold and is recovered through gas rates charged to customers (see Note 5).

ACCOUNTING FOR CONTRACTS INVOLVED IN ENERGY TRADING AND RISK MANAGEMENT ACTIVITIES

In December 1998, the EITF of the FASB reached consensus on EITF Issue No. 98-10 which requires that energy trading contracts should be marked-to-market (measured at fair value determined as of the balance sheet date) with the gains and losses included in earnings. Effective January 1, 1999, the Company adopted EITF Issue No. 98-10. The effect of the initial application of the new standard is reported as a cumulative effect of a change in accounting principle. (See Note 5)

CHANGE IN PRESENTATION

Certain prior year amounts have been reclassified to conform to the 2000 financial statement presentation.

The Company is an investor-owned integrated utility engaged in the generation, transmission, distribution and sale and trading of electricity, and the transportation, distribution and sale of natural gas. In addition, the Company provides energy and utility related services under its wholly-owned subsidiary, Avistar, Inc. ("Avistar").

Under current law, the Company is not in any direct retail competition with any other regulated electric and gas utility. The Restructuring Act in New Mexico, which was enacted into law on April 8, 1999, opens the state's electric power market to customer choice for certain customers beginning 2002 with the balance of customers obtaining open access mid 2002. The Restructuring Act requires that assets and activities subject to the PRC jurisdiction, primarily electric and gas distribution, and transmission assets and activities (collectively, the "regulated business"), be separated from other competitive business, primarily electric generation and service and certain other energy services operations (collectively, "the unregulated businesses"). Such separation is required to be accomplished through the creation of at least two separate corporations. The Company has decided to accomplish the mandated separation by the formation of a holding company and the transfer of the regulated businesses to a newly-created, wholly owned subsidiary of such holding company, subject to various regulatory and other approvals.

nature of business and segment information (continued)

Under existing deadlines, corporate separation of the regulated business from the competitive businesses must be completed by August 1, 2001. However, the New Mexico Legislature is currently considering various legislative actions that could delay open access and activities under the Restructuring Act, including corporate separation.

As it currently operates, the Company's principal business segments are utility operations, which include the Electric Product Offering ("Electric") and the natural Gas Product Offering ("Gas"), and Generation and Trading Operations ("Generation"). The Electric Product Offering consists of two major business lines that include distribution and transmission. The transmission business line does not meet the definition of a segment due to its immateriality and is combined with the distribution business line for disclosure purposes.

Electric procures all of its electric power needs from the Company's Generation and Trading Operations. These inter-segment sales are priced using internally developed transfer pricing, and are not based on market rates. Customer electric rates are regulated by the PRC and determined on a basis that includes the recovery of the cost of power production by the Company's Generation and Trading Operations and a return on the related assets, among other things.

UTILITY OPERATIONS

electric

The Company provides jurisdictional retail electric service to a large area of north central New Mexico, including the cities of Albuquerque and Santa Fe, and certain other areas of New Mexico. Approximately 369,000, 361,000 and 358,000 retail electric customers were served by the Company at December 31, 2000, 1999 and 1998, respectively. The Company owns or leases 2,781 circuit miles of transmission lines, interconnected with other utilities east into Texas, west into Arizona, and north into Colorado and Utah.

gas

The Company's gas operations distributes natural gas to most of the major communities in New Mexico, including Albuquerque and Santa Fe, serving approximately 435,000, 426,000 and 419,000 customers as of December 31, 2000, 1999 and 1998, respectively. The Company's customer base includes both sales-service customers and transportation-service customers.

The Company obtains its supply of natural gas primarily from sources within New Mexico pursuant to contracts with producers and marketers.

GENERATION AND TRADING OPERATIONS

The Company's generation and trading operations serve four principal markets. These include sales to the Company's Utility Operations to cover jurisdictional electric demand, sales to firm-requirements wholesale customers, other contracted sales to third parties for a specified amount of capacity (measured in megawatts-MW) or energy (measured in megawatt hours-MWh) over a given period of time and energy sales made on an hourly basis at fluctuating, spot-market rates. As of December 31, 2000, the total net generation capacity of facilities owned or leased by the Company was 1,653 MW, including a 132 MW power purchase contract accounted for as an operating lease. In addition to generation capacity, the Company purchases power in the open market.

UNREGULATED

The Company's wholly-owned subsidiary, Avistar, was formed in August 1999 as a New Mexico corporation and is currently engaged in certain unregulated, non-utility businesses, including energy and utility-related services previously operated by the Company. Unregulated also includes certain corporate activities, which are not material.

RISKS AND UNCERTAINTIES

The Company's future results may be affected by changes in regional economic conditions; the outcome of labor negotiations with unionized employees; fluctuations in fuel, purchased power and gas prices; the actions of utility regulatory commissions; changes in law; environmental regulations and external factors such as the weather. As a result of state and Federal regulatory reforms, the public utility industry is undergoing a fundamental change. As this occurs, the electric generation business is transforming into a competitive marketplace. The Company's future results will be impacted by its ability to recover its stranded costs, the market price of electricity and natural gas costs incurred previously in providing power generation to electric service customers, and the costs of transition to an unregulated status. In addition, as a result of deregulation, the Company may face competition from companies with greater financial and other resources.

Summarized financial information by business segment for 2000, 1999 and 1998 is as follows:

(In thousands)	Utility					
2000	**Electric**	**Gas**	**Total**	**Generation**	**Unregulated**	**Consolidated**
Operating revenues:						
External customers	538,758	319,924	858,682	750,434	2,158	1,611,274
Intersegment revenues	707	—	707	324,744	—	325,451
Depreciation and amortization	32,410	19,994	52,404	40,628	27	93,059
Interest income	1,158	517	1,675	39,439	7,581	48,695
Net interest charges	17,771	11,089	28,860	36,065	517	65,442
Income tax expense (benefit)						
From continuing operations	27,883	7,576	35,459	44,541	(5,656)	74,344
Operating income (loss)	56,827	18,600	75,427	80,359	(23,312)	132,474
Segment net income (loss)	39,711	10,885	50,596	74,095	(23,745)	100,946
Total assets	707,837	521,636	1,229,473	1,410,554	254,206	2,894,233
Gross property additions	51,815	40,418	92,233	53,025	1,620	146,878
1999						
Operating revenues:						
External customers	540,867	236,711	777,578	371,109	8,855	1,157,542
Intersegment revenues	707	—	707	318,872	—	319,579
Depreciation and amortization	31,113	19,210	50,323	40,253	2,084	92,660
Interest income	76	1,066	1,142	39,439	7,581	48,162
Net interest charges	19,822	13,585	33,407	36,561	699	70,667
Income tax expense (benefit)						
From continuing operations	23,806	2,299	26,105	25,454	(9,249)	42,310
Operating income (loss)	57,769	16,102	73,871	58,561	(12,352)	120,080
Cumulative effect of a change in						
Accounting Principle, net of tax	—	—	—	3,541	—	3,541
Segment net income (loss)	37,499	2,780	40,279	57,068	(14,192)	83,155
Total assets	734,898	449,790	1,184,688	1,445,145	93,434	2,723,267
Gross property additions	42,253	27,150	69,403	23,899	2,334	95,636
1998						
Operating revenues:						
External customers	555,568	255,974	811,542	279,636	1,267	1,092,445
Intersegment revenues	707	—	707	362,722	—	363,429
Depreciation and amortization	30,586	14,961	45,547	37,114	3,480	86,141
Interest income	35	957	992	16,927	17,150	35,069
Net interest charges	10,211	6,498	16,709	45,559	949	63,217
Income tax expense (benefit)						
from continuing operations	21,339	9,526	30,865	36,194	(10,768)	56,291
Operating income (loss)	40,386	19,051	59,437	91,462	(15,250)	135,649
Discontinued Operations						
net of tax	—	—	—	—	(12,437)	(12,437)
Segment net income (loss)	32,219	13,761	45,980	65,610	(28,908)	82,682
Total assets	732,609	417,948	1,150,557	1,469,635	48,410	2,668,602
Gross property additions	55,566	36,963	92,529	30,557	5,744	128,830

On August 4, 1998, the Company adopted a plan to discontinue the natural gas trading operations of its Energy Services Business Unit and completely discontinued these operations on December 31, 1998 (see Note 13).

The Company is subject to the provisions of SFAS 71, with respect to operations regulated by the PRC. Regulatory assets represent probable future revenue to the Company associated with certain costs which will be recovered from customers through the ratemaking process. Regulatory liabilities represent probable future reductions in revenues associated with amounts that are to be credited to customers through the ratemaking process. Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31, relate to the following:

(In thousands)	Year Ended December 31	
	2000	1999
Assets:		
Current:		
PGAC	$ 46,390	$ 19,310
Gas Take-or-Pay Costs	1,214	4,746
Subtotal	47,604	24,056
Deferred:		
Deferred Income Taxes	33,848	35,713
Loss on Reacquired Debt	7,687	8,133
Gas Imputed Revenues	2,117	7,290
Gas Reservation Fees	-	7,029
Deferred Customer Expense on Gas Assets Sale	7,984	6,468
Gas Retirees' Health Care Costs	1,724	3,264
Proposed Transmission Line Costs	2,377	2,432
Gas Rate Case Costs	-	1,571
Other	482	331
Subtotal	56,219	72,731
Stranded and Transition Assets	170,630	123,167
Total Assets	274,453	219,454
Liabilities:		
Deferred:		
Deferred Income Taxes	(43,834)	(46,815)
Gas Regulatory Reserve	(980)	(20,830)
Customer Gain on Gas Assets Sale	(7,226)	(7,226)
DOE Line Acquisition	(2,490)	(3,083)
Gain on Reacquired Debt	(1,791)	(708)
Other	(568)	(607)
Subtotal	(56,889)	(79,269)
Stranded and Transition Liabilities	(29,359)	(24,319)
Total Liabilities	(86,248)	(103,588)
Net Regulatory Assets	$ 188,205	$ 115,866

Substantially all of the Company's regulatory assets and regulatory liabilities are reflected in rates charged to customers or have been addressed in a regulatory proceeding.

In 1999, the State of New Mexico enacted the Restructuring Act that provides guidelines to deregulate power generation activities in New Mexico and opens the state's power markets to customer choice beginning 2002, according to the currently effective schedule.

The Restructuring Act recognizes that electric utilities should be permitted a reasonable opportunity to recover an appropriate amount of the costs previously incurred in providing electric service to their customers ("stranded costs"). Stranded costs represent all costs associated with generation related assets, currently in rates, in excess of the expected competitive market price and include plant decommissioning costs, regulatory assets, and lease and lease-related costs. Utilities will be allowed to recover no less than 50% of stranded costs through a non-bypassable charge on all customer bills for five years after implementation of customer choice. The PRC could authorize a utility to recover up to 100% of its stranded costs if the PRC finds that recovery of more than 50%: (i) is in the public interest; (ii) is necessary to maintain the financial integrity of the public utility; (iii) is necessary to continue adequate and reliable service; and (iv) will not cause an increase in rates to residential or small business customers during the transition period. The Restructuring Act also allows for the recovery of nuclear decommissioning costs by means of a separate wires charge over the life of the underlying generation assets.

Approximately $141 million of costs associated with the unregulated businesses under the Restructuring Act were established as regulatory assets. Because of the Company's belief that recovery is probable, these regulatory assets continue to be classified as regulatory assets, although the Company has discontinued Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation" (SFAS 71) and adopted Statement of Financial Accounting Standards No. 101, "Regulated Enterprises—Accounting for the Discontinuance of Application of FASB Statement 71." In 2000, the Company expensed $6.6 million of these assets based on management's view of the probable financial outcome of restructuring in New Mexico upon existing circumstances. If discussions with the PRC staff and other parties result in a settlement in which the amount the Company recovers for stranded costs is less than the amount it has recorded on the balance sheet as regulatory assets, the Company will be required to write–off the difference between its recovery of these costs and the amount it has currently recorded. Likewise, if a delay in corporate separation occurs, the Company may be required to write-off all or a portion of these assets due to the uncertainty of recovery resulting from enactment of the delay. However, Senate Bill 266 as amended establishes certain regulatory provisions affecting these costs, which if enacted along with the delay, will allow the Company to recover mine reclamation costs.

Pursuant to the Restructuring Act, utilities will also be allowed to recover in full any prudent and reasonable costs incurred in implementing full open access ("transition costs"). The transition costs will be recovered through 2007 under the current schedule by means of a separate wires charge. The Company estimates these costs as being in excess of $46 million, including allowances for certain costs which are non-deductible for income tax purposes. Transition costs include professional fees, financing costs including underwriting fees, consents relating to the transfer to assets, management information system changes including billing system changes and public and customer communications. Recoverable transition costs will be capitalized and amortized over the recovery period to match related revenues. Costs not recoverable will be expensed when incurred unless otherwise capitalizable under the accounting rules.

Regulatory assets and liabilities reflected in the Consolidated Balance Sheets as of December 31, related to stranded or transitions costs are as follows:

(In thousands)	2000	1999
Assets:		
Transition Costs	$ 19,069	$ 4,293
Mine Reclamation Costs	113,856	78,856
Deferred Income Taxes	35,726	37,725
Loss on Reacquired Debt	1,979	2,293
Subtotal	170,630	123,167
Liabilities:		
Deferred Income Taxes	(20,696)	(15,091)
PVNGS Prudence Audit	(5,434)	(5,809)
Settlement Due Customers	(3,205)	(3,384)
Gain on Reacquired Debt	(24)	(35)
Subtotal	(29,359)	(24,319)
Net Stranded Cost and Transition Cost	$ 141,271	$ 98,848

Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, the Company believes that its net regulatory assets are probable of future recovery.

Changes in common stock, additional paid-in capital and retained earnings are as follows:

(Dollars in thousands)	Common Stock			
	Number Of Shares	Aggregate Par Value	Additional Paid-In Capital	Retained Earnings
Balance at December 31, 1998	41,774,083	208,870	465,386	186,220
Stock repurchases	(1,070,700)	(5,353)	(13,446)	—
Tax benefit from exercise of stock option	—	—	1,453	—
Net earnings	—	—	—	83,155
Dividends:				
Cumulative preferred stock	—	—	—	(586)
Common Stock	—	—	—	(40,960)
Balance at December 31, 1999	40,703,383	203,517	453,393	227,829
Stock Repurchase	(1,585,584)	(7,928)	(19,939)	—
Exercise of stock options	—	—	(1,232)	—
Net earnings	—	—	—	100,946
Dividends:				
Cumulative preferred stock	—	—	—	(586)
Common Stock	—	—	—	(31,346)
Balance at December 31, 2000	39,117,799	195,589	432,222	296,843

COMPREHENSIVE INCOME

Changes in comprehensive income are as follows:

(In thousands)	Year Ended December 31		
	2000	1999	1998
Net Earnings	$ 100,946	$ 83,155	$ 82,682
Other Comprehensive Income, net of tax:			
Unrealized gain (loss) on securities:			
Unrealized holding gains arising from the period	2,794	4,120	1,519
Less reclassification adjustment for gains included in net income	(5,173)	(4,282)	(673)
Minimum pension liability adjustment	—	1,387	(205)
Total Other Comprehensive Income	(2,379)	1,225	641
Total Comprehensive Income	$ 98,567	$ 84,380	$ 83,323

The Company's investments held in rabbi trust for certain retirement benefits are classified as available-for-sale, and accordingly unrealized holding gains and losses are recognized as a component of comprehensive income. Realized gains and losses are included in earnings. Net losses related to the Company's pension plans, not yet recognized as net periodic pension costs (or additional minimum liability) are reported as a component of comprehensive income. Changes in the liability are adjusted as necessary. All components of comprehensive income are recorded, net of any tax benefit or expense. A deferred asset or liability is established for the resulting temporary difference.

COMMON STOCK

The number of authorized shares of common stock with par value of $5 per share is 80 million shares. The declaration of common dividends is dependent on a number of factors, including the extent to which cash flows will support dividends, the availability of retained earnings, the financial circumstances and performance of the Company and the PRC's decisions on the Company's various regulatory cases currently pending. In addition, the ability to recover stranded costs in deregulation, future growth plans and the related capital requirements and standard business considerations will also affect the Company's ability to pay dividends.

In March 1999, the Company's Board of Directors approved a plan to repurchase up to 1,587,000 shares of the Company's outstanding common stock with maximum purchase price of $19.00 per share. In December 1999, the Company's Board of Directors authorized the Company to repurchase up to an additional $20.0 million of the Company's common stock. As of December 31, 1999, the Company had repurchased 1,070,700 shares of its previously outstanding common stock at a cost of $18.8 million. From January 2, 2000 through March 31, 2000, the Company repurchased an additional 1,167,684 shares of its previously outstanding common stock at a cost of $18.9 million. On August 8, 2000, the Company's Board of Directors approved a plan to repurchase up to $35 million of the Company's common stock through the end of the first quarter of 2001. From August 8, 2000 through December 31, 2000, the Company repurchased an additional 417,900 shares of its outstanding common stock at a cost of $9.0 million. The Company may from time-to-time repurchase additional common stock for various corporate purposes.

On September 16, 1996, the Company implemented a dividend reinvestment and stock purchase plan for investors, including customers and employees. The plan, called PNM Direct, also includes safekeeping services and automatic investment features. The Company's stock is purchased in the open market to meet plan requirements.

CUMULATIVE PREFERRED STOCK

The number of authorized shares of cumulative preferred stock is 10 million shares. The Company has 128,000 shares, 1965 Series, 4.58%, stated value of $100 per share, of cumulative preferred stock outstanding. The 1965 Series does not have a mandatory redemption requirement but may be redeemable at 102% of the par value with accrued dividends. The holders of the 1965 Series are entitled to payment before holders of common stock in the event of any liquidation or dissolution or distribution of assets of the Company. In addition, the 1965 Series is not entitled to a sinking fund and cannot be converted into any other class of stock of the Company. The Company's restated articles of incorporation limit the amount of preferred stock which may be issued. The earnings test in the Company's restated articles of incorporation currently allows for the issuance of additional preferred stock.

LONG-TERM DEBT

The Company has $268,420,000 of long-term debt that matures in August 2005.

On March 11, 1998, the Company modified its 1947 Indenture of Mortgage and Deed of Trust; no future bonds can be issued under the mortgage. The first mortgage bonds continue to serve as collateral for the tax-exempt pollution control revenue bonds ("PCBs") in the outstanding principal amount of $111 million.

In March 1998, the Company replaced the first mortgage bonds collateralizing $463 million of PCBs with senior unsecured notes ("SUNs") which were issued under a new senior unsecured note indenture. Also, in March 1998, the Company retired $140 million principal amount of first mortgage bonds. While first mortgage bonds continue to serve as collateral for PCBs in the outstanding principal amount of $111 million, the lien of the mortgage was substantially reduced to cover only the Company's ownership interest in PVNGS. With the exception of the $111 million of PCBs secured by first mortgage bonds, the SUNs are and will be the senior debt of the Company.

In August 1998, the Company issued and sold $435 million of SUNs in two series, the 7.10% Series A due August 1, 2005, in the principal amount of $300 million, and the 7.50% Series B due August 1, 2018, in the principal amount of $135 million. These SUNs were issued under an indenture similar to the indenture under which the SUNs were issued in March 1998, and it is expected that future long-term debt financings will be similarly issued.

On October 28, 1999, tax-exempt pollution control revenue bonds of $11.5 million with an interest rate of 6.60% were issued to partially reimburse the Company for expenditures associated with its share of a recently completed upgrade of the emission control system at SJGS.

In 1999, the Company retired $31.6 million of its 7.10% senior unsecured notes through open market purchases, utilizing the funds from operations and the funds from temporary investments. In January 2000, the Company retired $35.0 million of its 7.5% senior unsecured notes through open market purchases utilizing funds from operations and the funds from temporary investments. The gains recognized on these purchases were immaterial.

capitalization (continued)

REVOLVING CREDIT FACILITY AND OTHER CREDIT FACILITIES

At December 31, 2000, the Company had a $150 million unsecured revolving credit facility (the "Facility") with an expiration date of March 11, 2003. The Company must pay commitment fees of 0.1875% per year on the total amount of the Facility. There were no outstanding borrowings under the Facility as of December 31, 2000, and the Company was in compliance with all covenants under the Facility.

The Company leases interests in Units 1 and 2 of PVNGS, certain transmission facilities, office buildings and other equipment under operating leases. The lease expense for PVNGS is $66.3 million per year over base lease terms expiring in 2015 and 2016. Covenants in the Company's PVNGS Units 1 and 2 lease agreements limit the Company's ability, without consent of the owner participants and bondholders in the lease transactions, (i) to enter into any merger or consolidation, or (ii) except in connection with normal dividend policy, to convey, transfer, lease or dividend more than 5% of its assets in any single transaction or series of related transactions.

Future minimum operating lease payments (in thousands) at December 31, 2000 are:

2000	$ 78,998
2001	78,884
2002	78,881
2003	78,881
2004	78,881
Later years	723,305
Total minimum lease payments	$ 1,117,830

Operating lease expense, inclusive of PVNGS leases, was approximately $81.6 million in 2000, $81.1 million in 1999 and $82.6 million in 1998. Aggregate minimum payments to be received in future periods under noncancelable subleases are approximately $4.1 million.

The Company uses derivative financial instruments to manage risk as it relates to changes in natural gas and electric prices and adverse market changes for investments held by the Company's various trusts. The Company also uses certain derivative instruments for bulk power electricity trading purposes in order to take advantage of favorable price movements and market timing activities in the wholesale power markets.

The estimated fair value of the Company's financial instruments (including current maturities) at December 31, is as follows:

(In thousands)	2000		1999	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ (953,823)	$ (930,359)	$ (988,489)	$ (932,687)
Investment in PVNGS Lessors' Notes	405,960	440,079	424,605	455,888
Derivatives	4,296	194,372	117	(25,921)
Decommissioning Trust	54,977	54,977	51,752	51,752
Fossil-Fueled Plant Decommissioning Trust	4,760	4,760	4,591	4,591
Rabbi Trust	12,284	14,281	16,901	16,931

Fair value is based on market quotes provided by the Company's investment bankers and trust advisors and the Company's risk management models.

The carrying amounts reflected on the consolidated balance sheets approximate fair value for cash, temporary investments, and receivables and payables due to the short period of maturity.

The Company is exposed to credit losses in the event of non-performance or non-payment by counterparties. The Company uses a credit management process to assess and monitor the financial conditions of counterparties. The Company's credit risk with its largest counterparty as of December 31, 2000 was $16.7 million.

NATURAL GAS CONTRACTS

Pursuant to a 1997 order issued by the NMPUC, predecessor to the PRC, the Company has previously entered into swaps to hedge certain portions of natural gas supply contracts in order to protect the Company's natural gas customers from the risk of adverse price fluctuations in the natural gas market. The financial impact of all hedge gains and losses from swaps is recoverable through the Company's purchased gas adjustment clause as deemed prudently incurred by the PRC.

As a result, earnings were not affected by gains or losses generated by these instruments. The Company hedged 40% of its natural gas deliveries during the 1998-1999 heating season. Less than 15.5% of the 1998-1999 heating season portfolio was hedged using financial hedging contracts. The Company hedged a portion of its 1999-2000 heating season gas supply portfolio through the use of both physical and financial hedging tools. Less than 9.1% of the Company's 1999-2000 heating season portfolio was hedged using financial hedging contracts.

The Company contracted for gas price caps, a type of hedge, to protect its natural gas customers from price risk during the 2000-2001 heating season through the use of financial hedging tools. The Company expended $5 million to purchase price cap options that limit the maximum amount the Company would pay for gas during the winter heating season. The Company recovered the $5 million in hedging costs during the months of October and November 2000 in equal $2.5 million allotments as a component of the PGAC. Results of the winter 2000-2001 hedging activities were an estimated $27 million benefit to system gas supply customers in the form of lower gas costs, net of the cost of the price caps.

FUEL HEDGING

The Company's Generation and Trading Operations commenced a program to reduce its exposure to fluctuations in prices for gas and oil purchases used as a fuel source for some of its generation. The Generation and Trading Operations purchased futures contracts for a portion of its anticipated natural gas needs in the third quarter and fourth quarter. The futures contracts capped the Company's natural gas purchase prices at $3.70 to $3.99 per MMBTU and had a notional principal of $4.5 million. Simultaneously, a delivery location basis swap was purchased for quantities corresponding to the futures quantities to protect against price differential changes at the specific delivery points. A portion of financial instruments settled in the third quarter and the remaining in the fourth quarter. The Company accounted for these transactions as hedges; accordingly, gains and losses related to these transactions are deferred and recognized in earnings as an adjustment to its cost of fuel. The fuel hedge program ended in October 2000.

ELECTRICITY TRADING CONTRACTS

To take advantage of market opportunities associated with the purchase and sale of electricity, the Company's Generation and Trading Operations periodically enters into derivative financial instrument contracts. In addition, the Company enters into forward physical contracts and physical options. The Company generally accounts for these financial instruments as trading activities under the accounting guidelines set forth under EITF Issue No. 98-10, although at times the Company may enter into contracts that it may designate as hedges. As a result, all open contracts are marked to market at the end of each period. The physical contracts are subsequently recognized as revenues or purchased power when the actual physical delivery occurs. The Company implemented EITF Issue No. 98-10 as of January 1, 1999 and recorded as a cumulative effect of a change in accounting principle a gain of approximately $3.5 million, net of taxes, or $0.09 per common share, on net open physical electricity purchases and sales commitments considered to be trading activities.

Through December 31, 2000, the Company's wholesale electric trading operations settled trading contracts for the sale of electricity that generated $88.9 million of electric revenues by delivering 2.1 million KWh. The Company purchased $78.6 million or 1.9 million KWh of electricity to support these contractual sale and other open market sales opportunities.

As of December 31, 2000, the Company had open trading contract positions to buy $10.9 million and to sell $4.3 million of electricity. At December 31, 2000, the Company had a gross mark-to-market gain (asset position) on these trading contracts of $6.8 million and gross mark-to-market loss (liability position) of $11.4 million, with net mark-to-market loss (liability position) of $4.6 million. The mark-to-market valuation is recognized in earnings each period.

The Company's wholesale power marketing operations, including both firm commitments and trading activities, are managed through an asset backed strategy, whereby the Company's aggregate net open position is covered by its own *financial instruments (continued)*

excess generation capabilities. The Company is exposed to market risk if its generation capabilities were disrupted or if its jurisdictional load requirements were greater than anticipated. If the Company were required to cover all or a portion of its net open contract position, it would have to meet its commitments through market purchases. The Company's value–at–risk calculation considers this exposure (see Quantitative and Qualitative Disclosure About Market Risk).

NEW ACCOUNTING STANDARD

On January 1, 2001, the Company implemented Statement of Financial Accounting Standard No. 133, Accounting for Derivative Instruments and Hedging Activities (see Note 15 – New and Proposed Accounting Standards).

HEDGE OF TRUST ASSETS

As of December 31, 2000, the Company had about $33 million invested in domestic stocks in various trusts for nuclear decommissioning, executive retirement and retiree medical benefits. The Company uses financial derivatives based on the Standard & Poor's ("S&P") 500 Index to limit potential loss on these investments due to adverse market fluctuations. The options are structured as a collar, protecting the portfolio against losses beyond a certain amount and balancing the cost of that downside protection by forgoing gains above a certain level. If the S&P 500 Index is within the specified range when the option contract expires, the Company will not be obligated to pay, nor will the Company have the right to receive cash. In February 2000, certain contracts were terminated. These new contracts increase the downside protection and further limit the upside gain. Subsequently, the Company entered into similar contracts which expire on June 15, 2001. In October and November 2000, certain of these contracts were terminated. The Company recognized realized gains of $0.7 million for the year ended December 31, 2000, and recorded net unrealized gains of $3.0 million (pre-tax) on the market value of its options. The net effect of the collar instruments for the year ended December 31, 2000 were net pre-tax gains of $3.7 million.

In accordance with SFAS No. 128, Earnings per Share, dual presentation of basic and diluted earnings per share has been presented in the Consolidated Statements of Earnings. The following reconciliation illustrates the impact on the share amounts of potential common shares and the earnings per share amounts:

	Year Ended December 31		
Basic	**2000**	**1999**	**1998**
Net Earnings from Continuing Operations	$ 100,946	$ 79,614	$ 95,119
Discontinued Operations, net of tax (note 13):	—	—	(12,437)
Cumulative Effect of a Change in Accounting Principle, net of tax (note 14)	—	3,541	—
Net Earnings	100,946	83,155	82,682
Preferred Stock Dividend Requirements	586	586	586
Net Earnings Applicable to Common Stock	$ 100,360	$ 82,569	$ 82,096
Average Number of Common Shares Outstanding	39,487	41,038	41,774
Net Earnings (Loss) per Share of Common Stock:			
Earnings from continuing operations	$ 2.54	$ 1.93	$ 2.27
Discontinued operations (note 13)	—	—	(0.30)
Cumulative effect of a change in accounting principle (note 14)	—	0 .08	—
Net Earnings per Share of Common Stock (Basic)	$ 2.54	$ 2.01	$ 1.97

Diluted		Year Ended December 31 2000		1999		1998
Net Earnings from Continuing Operations	$	100,946	$	79,614	$	95,119
Discontinued Operations, net of tax (note 13)		—		—		(12,437)
Cumulative Effect of a Change in Accounting Principle, net of tax (note 14)		—		3,541		—
Net Earnings		100,946		83,155		82,682
Preferred Stock Dividend Requirements		586		586		586
Net Earnings Applicable to Common Stock	$	100,360	$	82,569	$	82,096
Average Number of Common Shares Outstanding		39,487		41,038		41,774
Diluted effect of common stock equivalents (a)		223		65		298
Average common and common equivalent shares Outstanding		39,710		41,103		42,072
Net Earnings (Loss) per Share of Common Stock:						
Earnings from continuing operations	$	2.53	$	1.93	$	2.25
Discontinued operations		—		—		(0.30)
Cumulative effect of a change in accounting principle		—		0.08		—
Net Earnings per Share of Common Stock (Diluted)	$	2.53	$	2.01	$	1.95

(a) Excludes the effect of average anti-dilutive common stock equivalents related to out of-the-money options of 105,336; 66,143; and 23,794 for the years ended 2000, 1999 and 1998, respectively.

Income taxes before discontinued operations and cumulative effect of a change in accounting principle consist of the following components:

(In thousands)		2000		1999		1998
Current Federal income tax	$	41,666	$	23,511	$	32,785
Current state income tax		13,726		8,502		11,451
Deferred Federal income tax		19,729		13,494		15,797
Deferred state income tax		2,368		210		(324)
Amortization of accumulated investment tax credits		(3,143)		(3,409)		(3,418)
Total income taxes	$	74,346	$	42,308	$	56,291
Charged to operating expenses	$	53,964	$	25,010	$	41,306
Charged to other income and deductions		20,382		17,298		14,985
Total income taxes	$	74,346	$	42,308	$	56,291

income taxes (continued)

The Company's provision for income taxes before discontinued operations and cumulative effect of a change in accounting principle differed from the Federal income tax computed at the statutory rate for each of the years shown. The differences are attributable to the following factors:

(In thousands)	2000	1999	1998
Federal income tax at statutory rates	$ 61,352	$ 42,673	$ 52,993
Investment tax credits	(3,143)	(3,409)	(3,418)
Depreciation of flow-through items	2,250	605	531
Gains on the sale and leaseback of PVNGS Units 1 and 2	(527)	(527)	(527)
Dividends received deduction	—	(1,301)	—
Annual reversal of deferred income taxes accrued at prior tax rates	(2,477)	(2,320)	(1,905)
Income tax related regulatory asset revaluation	6,552	—	—
State income tax	8,343	5,541	7,074
Other	1,996	1,046	1,543
Total income taxes	$ 74,346	$ 42,308	$ 56,291
Effective tax rate	42.41%	34.70%	37.18%

The components of the net accumulated deferred income tax liability were:

(In thousands)	2000	1999
Deferred Tax Assets:		
Alternative minimum tax credit carryforward	$ —	$ 18,420
Nuclear decommissioning costs	23,892	22,073
Regulatory liabilities related to income taxes	41,695	44,547
Other	69,469	52,199
Total deferred tax assets	135,056	137,239
Deferred Tax Liabilities:		
Depreciation	184,127	184,687
Investment tax credit	47,853	50,996
Fuel costs	24,808	15,984
Regulatory assets related to income taxes	67,435	71,170
Other	45,631	33,668
Total deferred tax liabilities	369,854	356,505
Accumulated deferred income taxes, net	$ 234,798	$ 219,266

The following table reconciles the change in the net accumulated deferred income tax liability to the deferred income tax expense included in the consolidated statement of earnings for the period:

Net change in deferred income tax liability per above table	$ 15,532
Change in tax effects of income tax related regulatory assets and liabilities	882
Tax effect of mark-to-market on investments available for sale	2,540
Deferred income tax expense from continuing operations for the period	$ 18,954

The Company has no net operating loss carryforwards as of December 31, 2000.

The Company defers investment tax credits related to rate regulated assets and amortizes them over the estimated useful lives of those assets. The Company anticipates that this practice will continue when the generation assets are no longer rate regulated upon full implementation of the Restructuring Act.

PENSION PLAN

The Company and its subsidiaries have a pension plan covering substantially all of their union and non-union employees, including officers. The plan is non-contributory and provides for benefits to be paid to eligible employees at retirement based primarily upon years of service with the Company and the average of their highest annual base salary for three consecutive years. The Company's policy is to fund actuarially-determined contributions. Contributions to the plan reflect benefits attributed to employees' years of service to date and also for services expected to be provided in the future. Plan assets primarily consist of common stock, fixed income securities, cash equivalents and real estate.

In December 1996, the Board of Directors approved changes to the Company's non-contributory defined benefit plan ("Retirement Plan") and the implementation of a 401(k) defined contribution plan effective January 1, 1998. Salaries used in Retirement Plan benefit calculations were frozen as of December 31, 1997. Additional credited service can be accrued under the Retirement Plan up to a limit determined by age and years of service. The Company contributions to the 401(k) plan consist of a 3 percent non-matching contribution, and a 75 percent match on the first 6 percent contributed by the employee on a before-tax basis. The Company contributed $8.9 and $8.4 million in the years ended December 31, 2000 and 1999.

The following sets forth the pension plan's funded status, components of pension costs and amounts at December 31:

(in thousands)	Pension Benefits	
	2000	**1999**
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$ 331,061	$ 330,048
Service cost	6,491	7,407
Interest cost	23,572	21,777
Actuarial gain	(30,934)	(12,797)
Benefits paid	(17,038)	(15,374)
Benefit obligation at end of period	313,152	331,061
Change in Plan Assets:		
Fair value of plan assets at beginning of year	361,640	330,556
Actual return on plan assets	45,225	46,458
Benefits paid	(17,038)	(15,374)
Fair value of plan assets at end of year	389,827	361,640
Funded Status	76,675	30,579
Unamortized transition assets	(1,158)	(2,322)
Unrecognized net actuarial gain	(57,445)	(12,209)
Unrecognized prior service cost	44	78
Prepaid pension cost	$ 18,116	$ 16,126
Weighted - Average Assumptions as of December 31,		
Discount rate	8.25%	7.50%
Expected return on plan assets	9.00%	8.75%
Rate of compensation increase	N/A	N/A

pension and other postretirement benefits (continued)

(in thousands)

	Pension Benefits		
	2000	1999	1998
Components of Net Periodic Benefit Cost:			
Service cost	$ 6,491	$ 7,407	$ 6,660
Interest cost	23,572	21,777	20,101
Expected return on plan assets	(30,923)	(27,466)	(26,755)
Amortization of prior service cost	(1,130)	(1,130)	(1,130)
Net periodic pension costs (benefit)	$ (1,990)	$ 588	$ (1,124)

OTHER POSTRETIREMENT BENEFITS

The Company provides medical and dental benefits to eligible retirees. Currently, retirees are offered the same benefits as active employees after reflecting Medicare coordination. The following sets forth the plan's funded status, components of net periodic benefit cost at December 31:

(in thousands)

	Pension Benefits	
	2000	1999
Change in Benefit Obligation:		
Benefit obligation at beginning of year	$ 73,765	$ 74,539
Service cost	1,053	1,402
Interest cost	5,428	4,782
Actuarial loss (gain)	1,465	(6,958)
Benefit obligation at end of period	81,711	73,765
Change in Plan Assets:		
Fair value of plan assets at beginning of year	41,825	37,602
Actual return on plan assets	3,661	5,269
Employer contribution	1,431	597
Benefits paid	(2,224)	(1,643)
Fair value of plan assets at end of year	44,693	41,825
Funded Status	(37,018)	(31,940)
Unamortized transition assets	3,181	(622)
Unrecognized prior service cost	21,805	23,617
Accrued postretirement benefits (cost)	$ (12,032)	$ (8,945)
Weighted – Average Assumptions as of December 31,		
Discount rate	8.25%	7.50%
Expected return on plan assets	9.00%	8.75%
Rate of compensation increase	N/A	N/A

(in thousands)	Pension Benefits		
	2000	**1999**	**1998**
Components of Net Periodic Benefit Cost:			
Service cost	$ 1,053	$ 1,402	$ 1,292
Interest cost	5,428	4,782	4,501
Expected return on plan assets	(3,572)	(3,135)	(2,943)
Amortization of prior service cost	1,817	1,817	1,817
Net periodic post retirement benefit cost	$ 4,726	$ 4,866	$ 4,667

The effect of a 1% increase in the health care trend rate assumption would increase the accumulated postretirement benefit obligation as of December 31, 2000, by approximately $12.9 million and the aggregate service and interest cost components of net periodic postretirement benefit cost for 2000 by approximately $1.6 million. The health care cost trend rate is expected to decrease to 5.5% by 2007 and to remain at that level thereafter.

EXECUTIVE RETIREMENT PROGRAM

The Company has an executive retirement program for a group of management employees. The program was intended to attract, motivate and retain key management employees. The Company's projected benefit obligation for this program, as of December 31, 2000, was $16.9 million, of which the accumulated and vested benefit obligation was $16.9 million. As of December 31, 2000, the Company has recognized an additional liability of $2.0 million for the amount of unfunded accumulated benefits in excess of accrued pension costs. The net periodic cost for 2000, 1999 and 1998 was $1.9 million, $2.3 million and $2.3 million, respectively. In 1989, the Company established an irrevocable grantor trust in connection with the executive retirement program. Under the terms of the trust, the Company may, but is not obligated to, provide funds to the trust, which was established with an independent trustee, to aid it in meeting its obligations under such program. Marketable securities in the amount of approximately $12.3 million (fair market value of $14.3 million) are presently in trust. No additional funds have been provided to the trust since 1989.

The Company's Performance Stock Plan ("PSP") is a non-qualified stock option plan, covering a group of management employees. Options to purchase shares of the Company's common stock are granted at the fair market value of the shares on the date of the grant. Options granted through December 31, 1995 vested on June 30, 1996 and have an exercise term of up to 10 years. All subsequent awards granted after December 31, 1995, vest three years from the grant date of the awards. Options granted or approved on or after February 9, 1998, can also vest upon retirement. The maximum number of options authorized are five million shares that could be granted through December 31, 2000.

On June 6, 2000, the shareholders approved a new employee stock incentive plan, the Omnibus Performance Equity Plan ("the Omnibus Plan"). The Omnibus Plan is subject to consummation of the share exchange to form the new holding company as part of separation under the Restructuring Act. The Omnibus Plan provides for the granting of Non-Qualified Stock Options, incentive stock options, restricted stock rights, performance shares, performance units and stock appreciation rights to officers and key employees. The total number of shares of common stock subject to awards under the Omnibus Plan may not exceed five million, subject to adjustment under certain circumstances defined in the Omnibus Plan.

In addition, the Company has a Director Retainer Plan ("DRP") which provides for payment of the Directors' annual retainer in the form of cash, restricted stock or options to purchase shares of the Company's common stock. The number of options granted in 2000 and 1999 under the DRP was 6,000 shares with an exercise price of $6.19 and 8,000 shares with an exercise price of $9.69, respectively. 4,000 options were exercised under the DRP during 2000. The maximum number of options authorized are 100,000 shares through April 30, 2002. The number of options outstanding as of December 31, 2000, was 31,000. Restricted Stock issuances are based on the fair market value of the Company's common stock on the date of grant and vest over three years. As of December 31, 2000, 14,985 shares of restricted stock issued under the DRP were outstanding.

The fair value of each option grant is determined on the date of grant using the Black-Scholes option-pricing model with the following average assumptions used for grants in 1998, 1999 and 2000, respectively: dividend yield of 3.75%, 4.9% and 2.98%; expected volatility of 26.78%, 30.29% and 26.43%, risk-free interest rates of 4.65%, 6.43%; and 5.11%.

stock option plans (continued)

A summary of the status of the Company's stock option plans at December 31, and changes during the years then ended is presented below. Prior periods have been restated for comparability purposes.

	2000		1999		1998	
Fixed Options	**Shares**	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**	**Shares**	**Weighted Average Exercise Price**
Outstanding at beginning of year	1,574,418	$ 18.187	1,014,242	$ 18.819	1,536,662	$ 17.704
Granted	2,078,500	$ 19.403	608,708	$ 17.397	10,000	$ 12.750
Exercised	296,027	$ 16.290	—	N/A	473,063	$ 14.663
Forfeited	20,670	$ 17.320	48,532	$ 18.649	59,357	$ 21.194
Outstanding at end of year	3,336,221		1,574,418		1,014,242	
Options exercisable at year-end	916,263		766,454		435,409	
Options available for future grant	—		2,183,624		2,752,806	
Weighted-average fair value of options granted during the year:						
PSP	$ 7.24		$ 3.89		N/A	
DRP	$ 6.98		$ 5.85		$ 7.32	

The following table summarizes information about stock options outstanding at December 31, 2000:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	**Weighted-Average Number Outstanding At 12/31/00**	**Weighted Remaining Contractual Life**	**Average Exercise Prices**	**Weighted Number Exercisable At 12/31/00**	**Average Exercise Prices**
$ 5.50 – $ 12.75	31,000	7.63 years	$ 8.605	25,000	$ 9.185
$ 11.50 – $ 24.313	3,305,221	8.55 years	$ 19.220	891,263	$ 19.109
	3,336,221	8.54 years	$ 19.121	916,263	$ 18.839

Had compensation cost for the Company's performance stock plan been determined consistent with SFAS No. 123, Accounting for Stock-Based Compensation, the effect on the Company's pro forma net earnings and pro forma earnings per share would be as follows (in thousands, except per share data):

	2000		1999		1998	
	As Reported	**Pro forma**	**As Reported**	**Pro forma**	**As Reported**	**Pro forma**
Net earnings:						
(available for Common)	$ 100,360	$ 96,735	$ 82,569	$ 81,573	$ 82,096	$ 81,554
Net earnings per share						
Basic	$ 2.54	$ 2.45	$ 2.01	$ 1.99	$ 1.97	$ 1.95
Diluted	$ 2.53	$ 2.44	$ 2.01	$ 1.98	$ 1.95	$ 1.95

The Company's construction expenditures for 2000 were approximately $147.0 million, including expenditures on jointly-owned projects. The Company's proportionate share of expenses for the jointly-owned plants is included in operating expenses in the consolidated statements of earnings.

At December 31, 2000, the Company's interests and investments in jointly-owned generating facilities are:

(In thousands) Station Fuel Type	Plant in Service	Accumulated Depreciation	Construction Work in Progress	Composite Interest
San Juan Generating Station (Coal)	$ 706,063	$ 351,618	$ 827	46.30%
Palo Verde Nuclear Generating Station (Nuclear)*	$ 197,141	$ 54,518	$ 25,291	10.20%
Four Corners Power Plant Units 4 and 5 (Coal)	$ 117,797	$ 74,000	$ 3,066	13.00%

** Includes the Company's interest in PVNGS Unit 3, the Company's interest in common facilities for all PVNGS units and the Company's owned interests in PVNGS Units 1 and 2.*

SAN JUAN GENERATING STATION ("SJGS")

The Company operates and jointly owns SJGS. At December 31, 2000, SJGS Units 1 and 2 are owned on a 50% shared basis with Tucson Electric Power Company, Unit 3 is owned 50% by the Company, 41.8% by Southern California Public Power Authority ("SCPPA") and 8.2% by Tri-State Generation and Transmission Association, Inc. Unit 4 is owned 38.457% by the Company, 28.8% by M-S-R Public Power Agency, ("M-S-R"), 10.04% by the City of Anaheim, California, 8.475% by the City of Farmington, 7.2% by the County of Los Alamos, and 7.028% by Utah Associated Municipal Power Systems.

PALO VERDE NUCLEAR GENERATING STATION ("PVNGS")

The Company is a participant in the three 1,270 MW units of PVNGS, also known as the Arizona Nuclear Power Project, with Arizona Public Service Company ("APS") (the operating agent), Salt River Project, El Paso Electric Company ("El Paso"), Southern California Edison Company, SCPPA and The Department of Water and Power of the City of Los Angeles. The Company has a 10.2% undivided interest in PVNGS, with portions of its interests in Units 1 and 2 held under leases. (See Note 11 for additional discussion.)

LONG-TERM POWER CONTRACTS

The Company has a power purchase contract with Southwestern Public Service Company ("SPS") which originally provided for the purchase of up to 200 MW, expiring in May 2011. The Company may reduce its purchases from SPS by 25 MW annually upon three years' notice. The Company provided such notice to reduce the purchase by 25 MW in 1999 and by an additional 25 MW in 2000. The Company has 39 MW of contingent capacity obtained from El Paso under a transmission capacity for generation capacity trade arrangement that increases to 70 MW from 1999 through 2003. In addition, the Company is interconnected with various utilities for economy interchanges and mutual assistance in emergencies.

In 1996, the Company entered into a long-term PPA for the rights to all the output of a new gas-fired generating plant. The plant received FERC approval for "exempt wholesale generator" status with respect to the gas turbine generating unit. The PPA's maximum dependable capacity is 132 MW. In July 2000, the plant went into operation. The gas turbine generating unit is operated by Delta and is located on the Company's retired Person Generating Station site in Albuquerque, New Mexico. Primary fuel for the gas turbine generating unit is natural gas, which is provided by the Company. In addition, the unit has the capability to utilize low sulfur fuel oil in the event natural gas is not available or cost effective. For accounting purposes, the PPA is treated as an operating lease.

The Company has been actively trading in the wholesale power market and has entered into and anticipates that it will continue to enter into power purchases to accommodate its trading activity.

commitments and contingencies (continued)

CONSTRUCTION COMMITMENT

The Company has committed to purchase a combustion turbine for $36.0 million. In February 2000, the Company made a 10% deposit toward the purchase price. The turbine is for a planned power generation plant with an estimated cost of approximately $63.0 million for which a contract has not been finalized. The planned plant is part of the Company's ongoing competitive strategy of increasing generation capacity over time.

PLAINS ACQUISITION

The Company and Tri-State Generation and Transmission Association, Inc. ("Tri-State") entered into an asset sale agreement dated September 9, 1999, pursuant to which Tri-State agreed to sell the Company certain assets acquired by Tri-State's merger with Plains Electric Generation and Transmission Cooperative, Inc. ("Plains"), consisting primarily of transmission assets, a fifty percent interest in an inactive power plant located near Albuquerque, and an office building in Albuquerque. The purchase price is $13.2 million, subject to adjustment at the time of closing with the transaction to close in two phases. The asset sale agreement contains standard covenants and conditions for this type of agreement. On July 1, 2000, the first phase was completed, and the Company acquired the 50 percent ownership in the inactive power plant and the office building. The second phase relating to the transmission assets is expected to close in the first quarter of 2001.

In addition, on July 1, 2000, the Company advanced $11.8 million to a former Plains cooperative member as part of an agreement for the Company to become the cooperative's power supplier. Approximately $4.5 million of this advance represents an inducement for entering into a 10 year power sales agreement. Accordingly, the Company has expensed this amount in the third quarter as a business development cost. The remaining $7.5 million will be repaid over 10 years. If the cooperative terminates the contract early, the whole $11.8 million advance must be repaid to the Company.

NEW CUSTOMER BILLING SYSTEM

On November 30, 1998, the Company implemented a new customer billing system. Due to a significant number of problems associated with the implementation of the new billing system, the Company was unable to generate appropriate bills for all its customers through the first quarter of 1999 and was unable to analyze delinquent accounts until November 1999.

Under PRC rules and PRC approved Company rules, the Company is required to issue customer bills on a monthly basis. The Company was granted a temporary variance, and the PRC began a hearing on whether the Company violated PRC rules, regulations or orders or the New Mexico Public Utility Act. The investigation was concluded on November 2, 1999, without the PRC imposing any civil penalty on the Company and with an approved stipulation that the Company be permitted to bill an additional service charge to customers who were not billed the appropriate electric service charge or gas access fee. The stipulation was limited to approximately $0.7 million in the November and December 1999 billing cycles.

Because of the implementation issues associated with the new billing system, the Company estimated retail gas and electric revenues through July 1999. Beginning with August 1999, the Company was able to determine actual revenues for all prior periods affected and began reconciling with previously estimated revenues. In December 1999, the Company completed its reconciliation of system revenues. As a result, 1999 revenues represented actual revenues as determined by the new billing system. The resulting reconciliation did not materially impact recorded revenues. However, a significant number of individual accounts required corrections.

As a result of the delay of normal collection activities, the Company incurred a significant increase in delinquent accounts, many of which occurred with customers that no longer have active accounts with the Company. As a result, the Company significantly increased its estimated bad debt costs throughout 1999.

The Company continued its analysis and collection efforts of its delinquent accounts resulting from the problems associated with the implementation of the new customer billing system throughout 2000 and identified additional bad debt exposure. By the end of 2000, the Company completed its analysis of its delinquent accounts and resumed its normal collection procedures. As a result, the Company has determined that $13.5 million of customer receivables will not be collectible. Based upon information available at December 31, 2000, the Company believes the allowance for doubtful accounts of $9.0 million is adequate for management's estimate of potential uncollectible accounts.

In addition, due to the significantly higher natural gas prices experienced in November and December 2000, the Company increased its bad debt expense by approximately $2 million in anticipation of higher than normal delinquency rates. The Company expects this trend to continue as long as natural gas prices remain higher than in the past years.

The following is a summary of the allowance for doubtful accounts during 2000, 1999 and 1998:

(In thousands)

	2000	1999	1998
Allowance for doubtful accounts, beginning of year	$ 12,504	$ 836	$ 783
Bad debt expense	9,980	11,496	3,325
Less: Write off (adjustments) of uncollectible accounts	13,521	(172)	3,272
Allowance for doubtful accounts, end of year	$ 8,963	$ 12,504	$ 836

ELECTRIC RATE CASE SETTLEMENT

On August 25, 1999, the PRC issued an order approving the rate case settlement resulting from the NMPUC's final order of November 30, 1998. The PRC ordered the Company to reduce its electric rates by $34.0 million annually retroactive to July 30, 1999. In addition, the order includes a rate freeze until electric competition is fully implemented in New Mexico or until January 1, 2003 whichever is earlier. The settlement reduced revenues by approximately $39 million and $19 million in 2000 and 1999, respectively.

GAS RATE ORDERS

On October 24, 2000, the PRC issued a final order approving a stipulation negotiated in the third quarter between the Company and the PRC staff which resolved all issues raised by the two remanded gas rate cases. The final order adds approximately $1.2 million to the Company's revenues in the final quarter of 2000, $4.7 million in 2001, and $3.9 million in 2002. The Company has reversed certain reserves against costs recovered in the settlement that were recorded against earnings at the time of the original regulatory orders, resulting in a one-time pre-tax gain of $4.6 million. This amount will be collected from customers in rates over the next 12 years.

NUCLEAR DECOMMISSIONING TRUST

In 1998, the Company and the trustee of the Company's master decommissioning trust sued several companies and individuals, in State District Court in Santa Fe County, for the under-performance of a corporate owned life insurance program. The program was used to fund a portion of the Company's nuclear decommissioning obligations for its 10.2% interest in PVNGS.

The parties reached a settlement agreement under which all claims were dismissed with prejudice on September 5, 2000 and the Company and trustee received $13.8 million in settlement proceeds.

PVNGS LIABILITY AND INSURANCE MATTERS

The PVNGS participants have insurance for public liability resulting from nuclear energy hazards to the full limit of liability under Federal law. This potential liability is covered by primary liability insurance provided by commercial insurance carriers in the amount of $200 million and the balance by an industry-wide retrospective assessment program. If losses at any nuclear power plant covered by the programs exceed the primary liability insurance limit, the Company could be assessed retrospective adjustments. The maximum assessment per reactor under the program for each nuclear incident is approximately $88 million, subject to an annual limit of $10 million per reactor per incident. Based upon the Company's 10.2% interest in the three PVNGS units, the Company's maximum potential assessment per incident for all three units is approximately $27.0 million, with an annual payment limitation of $3 million per incident. If the funds provided by this retrospective assessment program prove to be insufficient, Congress could impose revenue raising measures on the nuclear industry to pay claims. The United States Nuclear Regulatory Commission and Congress are reviewing the related laws. The Company cannot predict whether or not Congress will change the law. However, certain changes could possibly trigger "Deemed Loss Events" under the Company's PVNGS leases, absent waiver by the lessors.

The PVNGS participants maintain "all-risk" (including nuclear hazards) insurance for nuclear property damage to, and decontamination of, property at PVNGS in the aggregate amount of $2.75 billion as of January 1, 2001. The Company is a member of an industry mutual insurer which provides both the "all-risk" and increased cost of generation insurance to the Company. In the event of adverse losses experienced by this insurer, the Company is subject to an assessment. The Company's maximum share of any assessment is approximately $2.3 million per year.

commitments and contingencies (continued)

PVNGS DECOMMISSIONING FUNDING

The Company has a program for funding its share of decommissioning costs for PVNGS. The nuclear decommissioning funding program is invested in equities and fixed income instruments in qualified and non-qualified trusts. The results of the 1998 decommissioning cost study indicated that the Company's share of the PVNGS decommissioning costs excluding spent fuel disposal will be approximately $171.3 million (in 2000 dollars).

The Company funded an additional $3.9 million, $3.1 million and $3.0 million in 2000, 1999 and 1998, respectively, into the qualified and non-qualified trust funds. The estimated market value of the trusts at the end of 2000 was approximately $55 million.

NUCLEAR SPENT FUEL AND WASTE DISPOSAL

Pursuant to the Nuclear Waste Policy Act of 1982, as amended in 1987 (the "Waste Act"), the United States Department of Energy ("DOE") is obligated to accept and dispose of all spent nuclear fuel and other high-level radioactive wastes generated by all domestic power reactors. Under the Waste Act, DOE was to develop the facilities necessary for the storage and disposal of spent nuclear fuel and to have the first such facility in operation by 1998. DOE has announced that such a repository now cannot be completed before 2010.

The operator of PVNGS has capacity in existing fuel storage pools at PVNGS which, with certain modifications, could accommodate all fuel expected to be discharged from normal operation of PVNGS through 2002, and believes it could augment that storage with the new facilities for on-site dry storage of spent fuel for an indeterminate period of operation beyond 2002, subject to obtaining any required governmental approvals. The Company currently estimates that it will incur approximately $41.0 million (in 1998 dollars) over the life of PVNGS for its share of the fuel costs related to the on-site interim storage of spent nuclear fuel during the operating life of the plant. The Company accrues these costs as a component of fuel expense, meaning the charges are accrued as the fuel is burned. In 1998, the Company expensed $12.1 million for on-site interim nuclear storage costs related to nuclear fuel burned prior to 1998. In 2000, the Company expensed approximately $1.0 million for on-site interim nuclear fuel storage costs related to nuclear fuel burned during 2000. The operator of PVNGS currently believes that spent fuel storage or disposal methods will be available for use by PVNGS to allow its continued operation beyond 2002.

OTHER

There are various claims and lawsuits pending against the Company and certain of its subsidiaries. The Company is also subject to Federal, state and local environmental laws and regulations, and is currently participating in the investigation and remediation of numerous sites. In addition, the Company periodically enters into financial commitments in connection with business operations. It is not possible at this time for the Company to determine fully the effect of all litigation on its consolidated financial statements. However, the Company has recorded a liability where the litigation effects can be estimated and where an outcome is considered probable. The Company does not expect that any known lawsuits, environmental costs and commitments will have a material adverse effect on its financial condition or results of operations.

The normal course of operations of the Company necessarily involves activities and substances that expose the Company to potential liabilities under laws and regulations protecting the environment. Liabilities under these laws and regulations can be material and in some instances may be imposed without regard to fault, or may be imposed for past acts, even though the past acts may have been lawful at the time they occurred. Sources of potential environmental liabilities include the Federal Comprehensive Environmental Response Compensation and Liability Act of 1980 and other similar statutes.

The Company records its environmental liabilities when site assessments or remedial actions are probable and a range of reasonably likely cleanup costs can be estimated. The Company 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, the Company, records the lower end of this reasonably likely range of costs (classified as other long-term liabilities at undiscounted amounts).

The Company's recorded estimated minimum liability to remediate its identified sites is $6.8 million. The ultimate cost to clean up the Company'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; and the time periods over which site remediation is expected to occur. The Company believes that, due to these uncertainties, it is remotely possible that cleanup costs could exceed its recorded liability by up to $11.6 million. The upper limit of this range of costs was estimated using assumptions least favorable to the Company.

Remediation of identified sites previously used in operations, used by tenants or contaminated by former owners required spending of $1.6 million in 2000 and $4.4 million in 1999. In 2001, the Company anticipates spending $1.4 million for remediation and $0.7 million for control and prevention. The majority of the December 31, 2000 environmental liability is expected to be paid over the next five years, funded by cash generated from operations. Future environmental obligations are not expected to have a material impact on the results of operations or financial condition of the Company.

On August 4, 1998, the Company adopted a plan to discontinue the gas trading operations of its Energy Services Business Unit. Accordingly, the gas marketing operations of its Energy Services Business Unit are reported as discontinued operations. Estimated losses on the disposal of the gas marketing segment were $5.1 million (net of income tax benefit of $3.3 million), which includes a provision for anticipated operating losses prior to disposal.

Operating losses of the discontinued operations prior to the date of discontinuation were $7.3 million in 1998. This amount includes income tax benefits related to the losses from discontinued operations of $4.8 million in 1998. Total sales from the discontinued operations was $159.2 million in 1998. Prior to the decision to discontinue non-utility operations, such total sales and income tax benefits were included in operating revenues and operating expenses in the consolidated statement of earnings.

On November 9, 2000 the Company and Western Resources, Inc. (Western Resources) announced that both companies' boards of directors approved an agreement under which the Company will acquire the Western Resources electric utility operations in a tax-free, stock-for-stock transaction.

Under the terms of the agreement, the Company and Western Resources, whose utility operations consist of its Kansas Power and Light division and Kansas Gas and Electric subsidiary, will both become subsidiaries of a new holding company to be named at a future date. Prior to the consummation of this combination, Western Resources will reorganize all of its non-utility assets, including its 85 percent stake in Protection One and its 45 percent investment in ONEOK, into Westar Industries which will be spun off to Western Resources' shareholder, prior to the acquisition of Western's utility assets by the Company.

The new holding company will issue 55 million of its shares, subject to adjustment, to Western Resources' shareholders and Westar Industries. Before any adjustments, the new company will have approximately 94 million shares outstanding, of which approximately 41 percent will be owned by former Company shareholders and 59 percent will be owned by former Western Resources shareholders and Westar Industries.

Based on the Company's average closing price over the last ten days prior to the announcement of $27.325 per share, the indicated equity consideration of the transaction is approximately $1.50 billion, including conversion of the Westar Industries obligation. Approximately $2.93 billion of existing Western Resources debt, giving the transaction an aggregate enterprise value of approximately $4.44 billion. The Company plans to reduce and refinance a portion of the Western Resources debt. The new holding company will have a total enterprise value of approximately $6.5 billion ($2.6 billion in equity; $3.9 billion in debt and preferred stock).

The transaction will be accounted for as a reverse acquisition by the Company as Western Resources shareholders will receive the majority of the voting interests in the new holding company. For accounting purposes Western Resources will be treated as the acquiring entity. Accordingly, all of the assets and liabilities of the Company will be recorded at fair value in the business combination as required by the purchase method of accounting. In addition, the operations of the Company will be reflected in the reported results of the combined company only from the date of acquisition.

In the transaction, each Company share will be exchanged on a one-for-one basis for shares in the new holding company. Each Western Resources share will be exchanged for a fraction of a share of the new company. This exchange ratio will be finalized at closing, depending on the impact of certain adjustments to the transaction consideration. Since Western Resources and Westar Industries remain committed to reducing Western Resources' net debt balance prior to *proposed acquisition (continued)*

consummation of the transaction, they have agreed with the Company on a mechanism to adjust the transaction consideration based on additional equity contributions. Under this mechanism, Western Resources could undertake certain activities not affecting the utility operations to reduce the net debt balance of the utility. The effect of such activities would be to increase the number of new holding company shares to be issued to all Western Resources shareholders (including Westar Industries) in the transaction. In addition, Westar Industries has the option of making additional equity infusions into Western Resources that will be used to reduce the utility's net debt balance prior to closing. Up to $407 million of such equity infusions may be used to purchase additional new holding company common and convertible preferred stock.

The successful spin-off of Westar Industries from Western Resources is required prior to the consummation of the transaction. The transaction is also conditioned upon, among other things, approvals from both companies' shareholders and customary regulatory approvals from the Kansas Corporation Commission, the New Mexico Public Regulation Commission, the Federal Energy Regulatory Commission, the Nuclear Regulatory Commission, and the Department of Justice under the Hart-Scott-Rodino Antitrust Improvements Act of 1976. The new holding company expects to register as a holding company with the Securities and Exchange Commission under the Public Utility Holding Company Act of 1935. Management believes that the above mentioned approvals are expected to be obtained over the next 12 to 18 months, however should such approvals not to be obtained, final consummation of the proposed acquisition cannot occur.

DECOMMISSIONING

The Staff of the Securities and Exchange Commission ("SEC") has questioned certain of the current accounting practices of the electric industry regarding the recognition, measurement and classification of decommissioning costs for nuclear generating stations in financial statements of electric utilities. In February 2000, the Financial Accounting Standards Board ("FASB") issued an exposure draft regarding Accounting for Obligations Associated with the Retirement of Long-Lived Assets ("Exposure Draft"). The Exposure Draft requires the recognition of a liability for an asset retirement obligation at fair value. In addition, present value techniques used to calculate the liability must use a credit adjusted risk-free rate. Subsequent remeasures of the liability would be recognized using an allocation approach. The Company has not yet determined the impact of the Exposure Draft.

STATEMENT OF FINANCIAL ACCOUNTING STANDARDS NO. 133, *ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND HEDGING ACTIVITIES*, ("SFAS 133"):

SFAS 133 establishes accounting and reporting standards requiring derivative instruments to be recorded in the balance sheet as either an asset or liability measured at its fair value. SFAS 133 also requires that changes in the derivatives' fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset related results on the hedged item in the income statement, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting. In June 1999, FASB issued SFAS 137 to amend the effective date for the compliance of SFAS 133 to January 1, 2001. In June 2000, the FASB issued SFAS 138 that provides certain amendments to SFAS 133. The amendments, among other things, expand the normal sales and purchases exception to contracts that implicitly or explicitly permit net settlement and contracts that have a market mechanism to facilitate net settlement. The expanded exception excludes a significant portion of the Company's contracts that previously would have required valuation under SFAS 133. Effective January 1, 2001, the Company adopted SFAS 133, as amended.

The Company has identified all financial instruments that meet the definition of a derivative under SFAS 133, as amended, currently existing in the Company. Certain of the Company's identified derivative instruments are currently marked-to-market under EITF 98-10. The related gains and losses (unrealized and realized) for these derivative instruments are recorded as adjustments to operating revenues.

In addition, the financial instruments underlying the Company's corporate hedge of certain investments in its nuclear executive retirement and retiree medical benefits trusts meet the definition of a derivative under SFAS 133, as amended, and are currently marked to market. The related unrealized and realized losses are recorded as a component of other income and deductions on the Consolidated Statement of Earnings. The Company designated certain forward purchase contracts for electricity as cash flow hedges. The Company's designated cash flow hedges at January 1, 2001, were forward purchase contracts for the purchase of electric power for forecasted jurisdictional use during planned outages in 2001. The hedged risks associated with these instruments are the changes in cash flows related to forecasted purchase of electricity due to changes in the price of electricity on the spot market. Assessment of hedge effectiveness will be based on the changes in the forward price of electricity.

SFAS 133, as amended, provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period or periods during which the hedged forecasted transaction affects earnings. The results of hedge ineffectiveness and the change in fair value of a derivative that an entity has chosen to exclude from hedge effectiveness are required to be presented in current earnings.

Because the Company's derivative instruments as defined by SFAS 133, as amended, are currently marked to market or are classified as cash flow hedges, the adoption of SFAS 133, as amended, will not have an impact on the net earnings of the Company. However, the adoption of SFAS 133, as amended, will increase comprehensive income by $6.0 million, net of taxes. The physical contracts will subsequently be recognized as a component of the cost of purchased power when the actual physical delivery occurs. At January 1, 2001, the derivative instruments designated as cash flow hedges had a gross asset position of $9.9 million on the hedged transactions. See Note 5 for financial instruments currently marked-to-market.

The unaudited operating results by quarters for 2000 and 1999 are as follows:

(In thousands, except per share amount)	Quarter Ended			
2000	**March 31**	**June 30**	**September 30**	**December 31**
Operating Revenues	$ 321,291	$ 329,041	$ 499,477	$ 461,465
Operating Income	30,947	27,654	47,452	26,422
Earnings from Continuing Operations	21,952	17,986	46,913	14,096
Net Earnings	21,952	17,986	46,913	14,096
Net Earnings per share from Continuing Operations	0.55	0.45	1.19	0.36
Net Earnings per Share (Basic)	0.55	0.45	1.19	0.36
Net Earnings per Share (Diluted)	0.55	0.45	1.18	0.35
1999				
Operating Revenues	$ 272,818	$ 261,371	$ 340,604	$ 282,750
Operating Income	35,068	29,247	30,275	25,489
Earnings from Continuing Operations	23,130	18,172	21,401	16,911
Net Earnings (1)	26,671	18,172	21,401	16,911
Net Earnings per share from Continuing Operations	0.55	0.44	0.52	0.41
Net Earnings per Share (Basic)	0.64	0.44	0.52	0.41
Net Earnings per Share (Diluted)	0.63	0.44	0.52	0.41

(1) Effective January 1, 1999, the Company adopted EITF Issue No. 98-10, Accounting for Contracts Involved in Energy Trading and Risk Management Activities. The effect of the initial application of EITF Issue No. 98-10 was reported as a cumulative effect of a change in accounting principle which increased the Company's consolidated net income by approximately $3.5 million (after related income tax expense of approximately $2.3 million), or $.08 per common share.

In the opinion of management of the Company, all adjustments (consisting of normal recurring accruals) necessary for a fair statement of the results of operations for such periods have been included.

shareholders information:

ANNUAL STOCKHOLDERS' MEETING

The 2001 Annual Meeting of Stockholders will be held at 9:30 a.m. (MDT) on Tuesday, July 3, 2001 at:
The Albuquerque Convention Center, 401 2nd NW, Albuquerque, NM.
Proxies will be requested from stockholders when the notice of meeting and proxy statement are mailed on or about May 21, 2001.

STOCK LISTING

The Common Stock is listed on the New York Stock Exchange. The Common Stock ticker symbol is PNM. The press listing is PSvNM. As of December 31, 2000, there were 15,483 common shareholders of record.

TRANSFER AGENT AND REGISTRAR

PNM Shareholder Records Department, Alvarado Square – 1104, Albuquerque, NM 87158,
Telephone (toll-free): 800-545-4425, Fax: 505-241-4311, E-Mail: yjohnso@pnm.com

DIVIDEND REINVESTMENT AND DIRECT STOCK PURCHASE PLAN

PNM offers a dividend reinvestment and direct stock purchase plan as a service to all interested participants. In addition to full or partial reinvestment of dividends, the PNM Direct Plan gives shareholders the opportunity to make direct cash investments ranging from $50 to $5,000 as often as once a month. Information regarding the Plan can be obtained by calling Shareholder Records at 800-545-4425.

ADDITIONAL INFORMATION

The Company reports details concerning its operations and other matters annually to the Securities and Exchange Commission on Form 10-K, which is available without charge to the Company's security holders, upon written request to the Senior Vice President of Planning and Investor Services.

A supplement containing additional financial and operating data for the latest 10-year period may be obtained by writing to the Senior Vice President of Planning and Investor Services.

For up-to-date stock quotes, quarterly earnings results and other important information, visit the PNM web site at www.pnm.com or call 800-840-0PNM (800-840-0766).

CONTACT INFORMATION:

Corporate Headquarters

Public Service Company of New Mexico, Alvarado Square, Albuquerque, NM 87158, 505-241-2700

Investor Relations

Barbara L. Barsky, Senior Vice President, Planning and Investor Services, Telephone: 505-241-2662;
Fax: 505-241-2368; E-Mail: bbarsky@pnm.com

New Mexico Utility Shareholders Alliance

P.O. Box 728, Albuquerque, NM 87103

COMMON STOCK PRICES AND DIVIDENDS PAID: (in dollars)

	2000			1999		
QUARTER	DIVIDEND	HIGH	LOW	DIVIDEND	HIGH	LOW
1	$0.20	$16.688	$14.625	$0.20	$20.625	$14.844
2	$0.20	$18.000	$15.313	$0.20	$21.125	$16.875
3	$0.20	$26.440	$15.375	$0.20	$21.500	$16.750
4	$0.20	$28.313	$20.750	$0.20	$18.875	$15.438

board of directors

JOHN T. ACKERMAN, 59 [1990] ● ★ ♦
Chairman Emeritus
Chairman, Executive Committee
Retired President & CEO of PNM

ROBERT G. ARMSTRONG, 54 [1991] ● ★ ■
President of Armstrong Energy Corporation

JOYCE A. GODWIN, 57 [1989] ✚ ★ ■ ♦
Retired President and Secretary of
Presbyterian Healthcare Services

MANUEL LUJAN, JR., 72 [1994] ● ✚
Previously served as U.S. Secretary of the Interior, consults on U.S. governmental matters and is an insurance agent with Manuel Lujan Insurance, Inc.

BENJAMIN F. MONTOYA, 65 [1993] ✚
Retired Chairman,
President and CEO of PNM

THEODORE F. PATLOVICH, 73 [2000] ▲ ♦
Retired Vice Chairman and
Senior VP of Loctite Corporation

ROBERT M. PRICE, 70 [1992] ★ ■ ▲
President of PSV, Inc.
a technology consulting business

PAUL F. ROTH, 68 [1991] ★ ■ ▲ ♦
Retired President of the Texas Division
of Southwestern Bell Telephone Company

JEFFRY E. STERBA, 45 [2000] ★ ▲
Chairman, President and CEO of PNM

- ● Audit Committee
- ✚ Customer and Public Policy Committee
- ★ Executive Committee
- ▲ Finance Committee
- ■ Compensation and Human Resources Committee
- ♦ Nominating and Governance Committee
- [ ] Year elected PNM Board Member

This list is effective as of 3/1/01

officers of the company

JEFFRY E. STERBA, 45
Chairman, President & CEO

ROGER J. FLYNN, 58
Executive VP, Electric and Gas Services

WILLIAM J. REAL, 52
Executive VP, Power Production and Marketing

BARBARA L. BARSKY, 56
Senior VP, Planning and Investor Services

MARC D. CHRISTENSEN, 52
Senior VP, Enterprise Solutions

MAX H. MAERKI, 61
Senior VP and Chief Financial Officer

PATRICK T. ORTIZ, 51
Senior VP, General Counsel and Secretary

EDWARD PADILLA, JR., 47
Senior VP,
Bulk Power Marketing and Development

R. BLAKE RIDGEWAY, 42
Senior VP, Energy Services

ERNEST T. C'DEBACA, 47
VP, Governmental Affairs

MELVIN J. CHRISTOPHER, 40
VP, Operations and Engineering

PATRICK J. GOODMAN, 51
VP, Power Production

TERRY R. HORN, 48
VP and Treasurer

SARITA P. LOEHR, 43
VP, Customer Service

JOHN R. LOYACK, 37
VP, Corporate Controller and
Chief Accounting Officer

CINDY E. MCGILL, 44
VP, Regulatory and Public Policy

JOHN H. MYERS, 43
VP, Construction and Reliability

Design: STUDIO HILL DESIGN Photography: MICHAEL BARLEY STUDIO Separations and Printing: WOODS LITHOGRAPHICS

PNM

PUBLIC SERVICE COMPANY OF NEW MEXICO

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