Debt Service Coverage for Electric System Revenue Bonds

Debt service coverage for the Electric System Revenue Bonds was 2.21, 2.18 and 2.47 in 2012, 2011 and 2010, respectively. OPPD's senior lien bond indenture provides that additional bonds may not be issued unless estimated net receipts for each future year shall equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued. Transactions in 2012, 2011 and 2010 for the NC2 Separate Electric System were not included in the calculation because the Electric System Revenue Bonds are not secured by the Separate System.

Debt Ratio

The debt ratio is a measure of financial solvency and represents the share of debt to total capitalization (debt and net position). This ratio does not include the NC2 Separate Electric System Revenue Bonds since this debt is secured by revenues of the NC2 Participation Power Agreements. The debt ratio was 53.1% and 51.1% as of December 31, 2012 and 2011, respectively.

Retirement Plan and Other Post Employment Benefits

The Company provides retirement and other post employment benefits (OPEB) as full-time employees are not covered by Social Security. Actions have been taken to help offset the increase in these costs with plan design changes. Plan changes have impacted most employees, including an increase in the minimum age for retirement eligibility from 50 to 55 effective in 2013, a mandatory Cash Balance Retirement provision for employees hired after December 31, 2012, and the establishment of a separate OPEB Plan for employees hired after December 31, 2007.

The annual required contributions (ARC) for the defined employee benefit plans are calculated using actuarial valuations and are fully funded to ensure the Company is able to meet its obligations to plan members. The ARC for the defined benefit Retirement Plan was $53,463,000, $47,585,000 and $42,045,000 for the years 2012, 2011 and 2010, respectively. The employees' contribution percentage of pay was 6.2% for each of the three years in the period ended December 31, 2012. Employee contributions to the Retirement Plan were $11,517,000, $11,369,000 and $11,313,000 for the years 2012, 2011 and 2010, respectively. The ARC for the two OPEB plans totaled $30,698,000, $29,511,000 and $25,751,000 for the years 2012, 2011 and 2010, respectively. The increase in 2012 costs for benefit plans was primarily due to lower than expected investment returns on plan assets.

The Retirement Plan's funded status was reported in two different ways – the actuarial value of assets as a percentage of the present value of accrued plan benefits (PVAPB) and the actuarial value of assets as a percentage of the actuarial accrued liability (AAL). The PVAPB is the present value of benefits based on compensation and service to the date of the actuarial valuation. The PVAPB is the amount the Retirement Plan would owe participants if the Retirement Plan were frozen on the valuation date. The AAL is the present value of retirement benefits adjusted for assumptions for future increases in compensation and service attributable to past accounting periods, which is more representative of the expected benefit obligations. The Retirement Plan's funded status for the actuarial valuations was 81.8% 83% and 85.8% using PVAPB and 69.7%, 70.5% and 72% using AAL, as of January 1, 2012, 2011 and 2010, respectively.

Risk Management Practices

An Enterprise Risk Management (ERM) program is used to identify, quantify, prioritize and manage risks throughout the Company. As part of the ERM program, specific risk-mitigation plans and procedures are maintained to provide for focused and consistent efforts to mitigate various risk exposures. Several cross-functional risk committees are utilized to discuss and analyze potential risks that could hinder the achievement of OPPD's strategic objectives. Additionally, an Executive ERM Committee has been established to specifically discuss risk-related issues at the senior management level of the Company. An overview of the ERM program is provided to the Board of Directors annually.

Power marketing and fuel purchase activities are conducted within the normal course of business. Risks associated with power marketing and fuel contracting are managed within a risk-management control framework. Fuel expense represents a significant portion of generation costs and affects the ability to generate and market competitively priced power. A risk-management working group is responsible for identifying, measuring and mitigating various risk exposures related to power marketing and fuel purchase activities.

OPPD competes in the wholesale marketplace with other electric utilities and power marketers for off-system energy sales. To successfully compete in this market, the Company must be able to offer energy at competitive prices and obtain transmission services. Energy market prices may fluctuate substantially in a short period of time due to changes in the supply and demand of electricity. Counterparty credit risks are monitored closely on an ongoing basis. Significant changes in the Company's energy trading and marketing practices and processeses are anticipated with the implementation of the Integrated Marketplace by the Southwest Power Pool (SPP). The risks associated with these changes are being identified and plans are being established for their mitigation.

A Rate Stabilization Reserve was established in 1999 to assist in stabilizing retail electric rates. Funds from this reserve were used to help finance higher fuel costs and unexpected energy purchases in 2011 due to the extended outage at FCS to lessen the impact on customer-owners. The funds were partially replenished with FPPA recoveries and insurance proceeds in 2012. The balance of the fund was $24,612,000 and $0 as of December 31, 2012 and 2011, respectively. Additional proceeds from insurance recoveries were used to return the fund balance to $32,000,000 in January 2013. The balance of the reserve was maintained at $32,000,000 as of December 31, 2012 and 2011.

A Debt Retirement Reserve was established in 2003 to assist in managing the long-term risks associated with significant capital expenditures and related debt issuances. This reserve is used to meet challenges in retiring debt and maintaining adequate debt service coverage ratios. The reserve was used to provide additional revenues and funds of $17,000,000 and $24,000,000 in 2012 and 2011, respectively. With the strong financial results for 2010, $13,000,000 was added to the reserve to help meet economic challenges in future years. The balance of the fund was $14,000,000 and $48,000,000 as of December 31, 2012 and 2011, respectively. In 2013, $3,000,000 was transferred to the fund, which increased the fund to $17,000,000. The balance of the reserve was $17,000,000 and $34,000,000 as of December 31, 2012 and 2011, respectively.

The Company promotes ethical business practices and the highest standards in the reporting and disclosure of financial information. The Sarbanes-Oxley Act (Act) is intended to strengthen corporate governance of publicly traded companies. As a public utility, the Company is not required to comply with the Act, but the application of these requirements, where appropriate, ensures continued public trust in OPPD, protects the interest of its stakeholders and is a sound business practice. One of the most significant requirements of the Act pertains to management's documentation and assessment of internal controls. The Company's management assesses internal controls for significant business processes that impact financial reporting. This assessment includes documenting procedures, risks and controls for these processes and assessing the effectiveness and operation of the internal controls. In addition, the Company contracts with an independent third party to administer the receipt, communication and retention of employee concerns regarding business and financial practices.

Other Reserves

Other reserves are maintained to recognize potential liabilities that arise in the normal course of business. Additional information about other reserves follows.

- The Uncollectible Accounts Reserve is established for estimated uncollectible accounts from both retail and off-system sales. Accounts Receivable is reported net of the reserve for retail sales. A $5,000,000 reserve for off-system sales was established by the Board of Directors. This reserve is separately reported as a deferred inflow on the Statement of Net Position.
- The Workers' Compensation and Public Liability Reserves are established for the estimated liability for current workers' compensation and public liability claims.
- The Incurred But Not Presented Reserve is an insurance reserve that is required by state law due to the Company being self-insured for health care costs. The reserve is based on health insurance claims that have been incurred but not yet presented for payment.

CAPITAL RESOURCES

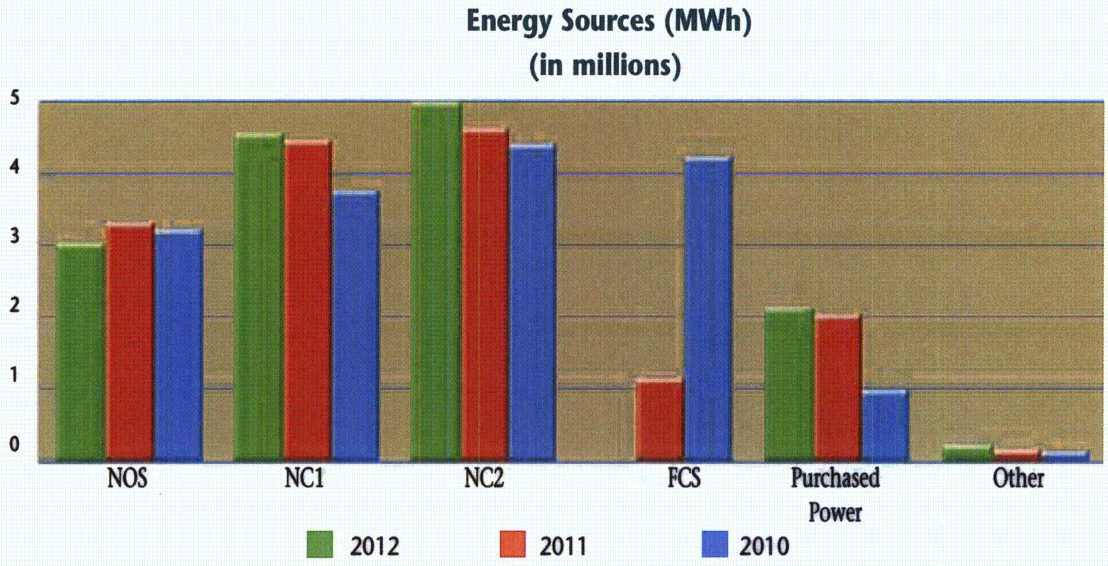
Generating Capability

Power requirements are supplied from the generating stations, leased generation and purchases of power. OPPD owns and operates eight generating stations, seven of which have a maximum summer net accredited capability of 3,208.8 megawatts (MW). (The net capability of the Valley Station wind turbine is not accredited.)

The following table lists owned generating units by fuel source and identifies the maximum summer net accredited capability (in MW) and percentage of the total for 2012.

		Capability	% of Total
Coal	Nebraska City Station Unit 1 (NC1)	651.5	
	Nebraska City Station Unit 2 (NC2)	684.6	
	North Omaha Station (NOS)	534.2	
	Subtotal Coal	1,870.3	58.3
Nuclear	Fort Calhoun Station (FCS)	478.6	14.9
Oil/Natural Gas	Cass County Station	323.2	
	Jones Street Station	122.7	
	North Omaha Station	92.5	
	Sarpy County Station	315.3	
	Subtotal Oil/Natural Gas	853.7	26.6
Other	Elk City Station (landfill-gas)	6.2	0.2
Total Owned Generation		3,208.8	100.0

The following chart shows the change in energy sources as compared to prior years due to the outage at FCS (in MWh).



Renewable Capability including Purchased Power Contracts

Renewable portfolio standards are currently mandated in several states but not in Nebraska. The Board of Directors has established a proactive goal to provide 10% of retail energy from renewable sources by 2020. The percentage of renewable energy increased from 4% in 2011 to 5.3% in 2012 and is expected to increase 15.1% in 2014. A purchased power contract with the Western Area Power Administration for 82 MW of hydro power is excluded from the goal.

The following table shows the renewable generation owned or purchased (in MW).

		Capability
OPPD Owned Generation		
	Elk City Station (landfill-gas)	6.2
	Valley Station (wind)	0.7
	Subtotal OPPD Owned Generation	6.9
Purchased Wind Generation		
	Ainsworth	10.0
	Elkhorn Ridge	25.0
	Flat Water	60.0
	Petersburg	40.5
	Broken Bow 1	18.0
	Crofton Bluffs	13.6
	Subtotal Purchased Wind Generation	167.1
Total Renewable Generation as of December 31, 2012		174.0
2014 Purchased Wind Generation		
	Broken Bow 2	45.0
	Prairie Breeze	200.6
	Subtotal 2014 Purchased Wind Generation	245.6
Total Expected Renewable Generation as of December 31, 2014		419.6

Capital Program

Electric system requirements, including the identification of future capital investments, are routinely evaluated to ensure current and future load requirements are served by a reliable, diverse and economical power supply. Capital investments are financed with revenues from operations, bond proceeds, investment income and cash on hand. Certain capital expenditures have been deferred, where possible, as a result of current FCS outage-related challenges. Capital expenditures were $17,027,000 under budget for 2012.

The following table shows actual capital program expenditures, including allowances for funds used during construction, for the last three years and projected expenditures for 2013 and 2014 (in millions).

	Projected		Actual		
Capital Program	**2014**	**2013**	**2012**	**2011**	**2010**
Production	$306.5	$ 79.7	$ 89.6	$103.3	$111.7
Transmission and Distribution	86.3	68.8	74.0	65.0	57.7
General	21.9	17.6	16.6	27.5	40.6
Total	$414.7	$166.1	$180.2	$195.8	$210.0

Production includes expenditures related to generating facilities. Additional information on significant expenditures follows.

- FCS expenditures include the extended power uprate and other plant improvement projects. The extended power uprate scheduled for completion in 2013 has been postponed to focus efforts on the restart and operations of FCS. Activities that were in progress will be completed, but no further related activities are forecasted prior to 2015.
- Production expenditures and projections include additional capital costs to comply with increasing environmental regulations.
- A natural gas pipeline and other equipment are being installed at the Nebraska City Station to use natural gas for a start-up and stabilization fuel source as an alternative to fuel oil.

Transmission and distribution system upgrades include the installation of new technologies and substation and distribution facilities to maintain system reliability, enhance efficiency and respond to load growth. The projected expenditures include the addition of transmission lines, new substations and equipment for increased system capacity.

General plant expenditures for 2012 and projected expenditures for 2013 and 2014 include the purchase of construction and transportation equipment and information technology upgrades.

Fort Calhoun Station Outage Update

FCS was taken out of service for a normal refueling outage in April 2011. Outage activities were suspended in June 2011 to protect facilities from rising river levels caused by the release of record amounts of water from dams along the Missouri River by the U.S. Army Corps of Engineers. The NRC placed FCS into a special category of their inspection manual, Chapter 0350, in December 2011. This Chapter is for nuclear power plants that are in extended shutdowns with performance issues. A Confirmatory Action Letter (CAL) with a restart checklist was issued by the NRC in June 2012 and revised on February 26, 2013. FCS will resume normal operations when all items on the NRC restart checklist are resolved.

Both the NRC's inspection and review process and OPPD's internal review process have proceeded more slowly than originally expected and have identified additional action items that will require more time than previously estimated. The most significant single action item identified was related to electrical penetrations in the containment building. After thorough analysis, it was determined that the replacement of selected electrical penetrations between the containment building and the general plant was the best long-term option for FCS. This project has an estimated cost of $10,000,000 and will delay the expected restart of normal FCS operations until late in the second quarter of 2013. Commercially reasonable efforts to restart FCS are being made as quickly as is prudently practicable, subject to NRC regulations and oversight. A precise restart date cannot be determined because of ongoing inspections and unfinished items on the restart checklist.

The extended outage has resulted in significant unplanned costs for OPPD. Internal cost reductions, outage insurance proceeds and the use of regulatory accounting have lessened the financial impact from these unexpected costs. The Board of Directors authorized the use of regulatory accounting to defer $70,627,000 of Recovery Costs (as previously defined) in 2012. The Recovery Costs will be amortized over a 10-year period after FCS operations resume and the station's regulatory rating is reclassified and increased to a more favorable NRC regulatory category. Any delay beyond the second quarter of 2013 will result in additional costs. The impact, if any, on OPPD's financial position due to any delays in the restart date beyond the second quarter of 2013 cannot be estimated at this time. Returning FCS to service continues to be a high priority as activities are being completed to resolve NRC concerns and restart normal operations.

GENERAL FACTORS AFFECTING OPPD AND THE ELECTRIC UTILITY INDUSTRY

OPPD and the electric industry continue to be affected by a number of factors that could impact the competitiveness and financial condition of all electric utilities.

Environmental Issues

The Cross-State Air Pollution Rule (CSAPR) was published on August 8, 2011, to improve air quality by reducing power plant emissions contributing to ozone and fine-particle pollution in other states. The final rule establishes a cap-and-trade system with state and unit specific allowance allocations to achieve desired emission reductions for nitrogen oxide and sulfur dioxide. Implementation of Phase I of the final rule was scheduled to begin in 2012, but the United States Court of Appeals for the District of Columbia issued an order on December 30, 2011, staying CSAPR pending judicial review. On August 21, 2012, the federal court vacated CSAPR stating the rule exceeds the statutory authority of the Environmental Protection Agency (EPA). The EPA will continue administering the Clean Air Interstate Rule (CAIR), the predecessor to CSAPR pending the promulgation of a valid replacement rule. The State of Nebraska is not covered by CAIR; therefore, OPPD remains unaffected at this time. However, the Company continues to prepare for stricter regulations with the execution, if necessary, of ultra low-sulfur coal purchase agreements, acquisition of additional renewable energy sources, continued implementation of sustainable energy and environmental stewardship initiatives and comprehensive studies on opportunities for older coal-fired generating units.

On December 16, 2011, the EPA finalized the Mercury and Air Toxics Standard (MATS). Compliance with this rule will be necessary by April 16, 2015. An additional year may be granted by local permitting agencies to facilitate installation of pollution control equipment. In October 2012, the Company requested a one-year extension for Nebraska City Station Unit 1 and North Omaha Station Units 1-5. In November 2012, these extensions were granted by the Nebraska Department of Environmental Quality and the City of Omaha, respectively. Studies are being conducted to determine optimal generating options for OPPD as a result of these and other environmental regulations.

Federal Energy Legislation

As a result of the 2012 elections, the 113th Congress will likely have a very similar position on energy issues to the previous Congress. Republicans continue to control the House of Representatives which greatly decreases the probability of legislation for a carbon cap-and-trade program for the electric utility industry being passed into law through the end of 2014. In 2011, the House of Representatives passed legislation that would block efforts by the EPA to regulate greenhouse gas emissions under the Clean Air Act. In 2012, the House of Representatives also passed legislation to block or delay other EPA regulatory proposals that are aimed primarily at fossil-fired electric generation facilities. The Democratic-controlled Senate did not pass similar legislation and, given the same Senate leadership in the 113th Congress, would likely continue to block any similar legislation passed by the House in 2013 and 2014.

Efforts on energy legislation are likely to be very limited and would focus on market-based approaches that will help create jobs and grow the economy, as well as possibly addressing the issue of long-term storage of high-level nuclear waste. While provisions like carbon cap-and-trade and a Renewable Energy Standard or a Clean Energy Standard could result in substantial rate increases if enacted into law, neither is considered likely during the two-year legislative session of the 113th Congress. OPPD will continue to monitor the status of energy and climate-change legislation in Congress and continue to provide input through public power industry groups and the Nebraska Congressional Delegation.

State of Nebraska Energy Legislation

During the 2012 session, the Nebraska Legislature did not enact any major changes affecting the electric utility industry. No major changes are expected in 2013.

Legislative Bill 388 (L.B. 388), Change Provisions Relating to Public Power and Provide for Construction of Certain Transmission Lines, was introduced in the Nebraska Legislature in January 2013. L.B. 388 would provide electric transmission owners, who belong to a Regional Transmission Organization (RTO), the right of first refusal to complete transmission projects in Nebraska that have been approved by the RTO. The purpose is to clarify that public power entities in Nebraska have the first right to construct, own, and maintain approved transmission lines.

During the 2010 session, the Nebraska Legislature enacted Legislative Bill 1048 (L.B. 1048), Wind for Export. L.B. 1048 provides new requirements to allow developers to build wind generation facilities for the purpose of exporting power outside the state of Nebraska, subject to certain requirements that protect the ratepayers of customer-owned utilities.

During the 2000 session, the Nebraska Legislature enacted Legislative Bill 901, which implemented recommendations to determine whether retail competition would be beneficial for Nebraska ratepayers. Reports for the Governor and Legislature on the conditions in the electric industry indicating whether retail competition would be beneficial for Nebraska's citizens are prepared at the request of the Power Review Board. All of the conditions for retail competition have not been met, based on the findings from the latest report, dated October 2010.

Transmission Access

On April 1, 2009, OPPD became a transmission-owning member of SPP, and all of the Company's transmission facilities were placed under the SPP open access transmission tariff. In addition to tariff administration services, SPP also provides reliability coordination services, generation reserve sharing, energy imbalance market services and transmission planning services to OPPD and SPP's other transmission-owning members.

SPP is expected to change to an Integrated Marketplace on March 1, 2014. The Integrated Marketplace is a centrally cleared energy market where OPPD generation assets will be dispatched and load obligations served accordingly based on inputs to the clearinghouse from all SPP market participants. Concurrently, OPPD's current Balancing Authority will be replaced by SPP's Consolidated Balancing Authority.

A 345-kilovolt power line being built by OPPD and Kansas City Power and Light (Midwest Transmission Project) will run from a substation at the Nebraska City Station to Sibley, Missouri. This project is one of several priority projects as determined by SPP and is expected to relieve congestion on the region's transmission system; improve reliability on the nation's energy grid; provide an additional gateway for renewable energy to reach utility customers across eastern Nebraska, northwest Missouri and the surrounding region; and improve opportunities for wind energy distribution once it becomes available. The project is currently in the transmission route selection phase, which includes input from the public and key stakeholders and is planned to be in service in 2017.

OPPD is a member of the Midwest Reliability Organization reliability region of the North American Electric Reliability Corporation. A reliability region is responsible for reliability standards and compliance for the interconnected utilities.

High-Level Nuclear Waste Repository

Under the Federal Nuclear Waste Disposal Act of 1982, the federal government assumed responsibility for the permanent disposal of spent nuclear fuel. The Department of Energy (DOE) currently does not have a federal government facility available for the long-term storage of spent nuclear fuel. OPPD remains responsible for the safe storage of spent nuclear fuel until the federal government takes delivery of this waste. The DOE has agreed to reimburse the Company for allowable costs incurred for managing and storing spent nuclear fuel and high-level waste due to the DOE's delay in accepting waste. No reimbursements were received in 2012. OPPD received $295,000 and $5,811,000 from the DOE in 2011 and 2010, respectively.

Critical Accounting Policies

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

Those judgments could materially impact the financial statements and disclosures based on varying assumptions, which may be appropriate to use. In addition, the financial and operating environment may have a significant effect on the operation of the business and on the results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies has not changed.

The following is a list of accounting policies that are significant to OPPD's financial condition and results of operation and require management's most significant, subjective or complex judgments. Each of these has a higher likelihood of resulting in materially different reported amounts under different conditions or using different assumptions.

Accounting Policies	Judgments/Uncertainties Affecting Application
Environmental Issues and Pollution-Remediation Obligations	• Approved methods for cleanup • Governmental regulations and standards • Cost estimates for future remediation options
Nuclear Plant Decommissioning	• Cost estimates for future decommissioning • Availability of facilities for waste disposal • Approved methods for waste disposal • Useful life of Fort Calhoun Station
Regulatory Mechanisms and Cost Recovery	• External regulatory requirements • Anticipated future regulatory decisions and their impact
Retirement Plan and Other Post Employment Benefits	• Assumptions used in computing the actuarial liability, including expected rate of return on Plan assets • Plan design
Self-Insurance Reserves for Claims for Employee-related Healthcare Benefits, Workers Compensation and Public Liability	• Cost estimates for claims • Assumptions used in computing the liabilities
Uncollectible Accounts Reserve	• Economic conditions affecting customers • Assumptions used in computing the liabilities
Unbilled Revenue	• Estimates for customer energy use and prices

SUMMARY OF THE FINANCIAL STATEMENTS

The basic Financial Statements, Notes and Management's Discussion and Analysis are designed to provide a general overview of OPPD's financial position. Questions concerning any of the information provided in this report should be directed to Investor Relations, 402-636-3286.

Report of Management

The management of Omaha Public Power District (OPPD) is responsible for the preparation of the following financial statements and for their integrity and objectivity. These financial statements conform to generally accepted accounting principles and, where required, include amounts which represent management's best judgments and estimates. OPPD's management also prepared the other information in this Annual Report and is responsible for its accuracy and consistency with the financial statements.

To fulfill its responsibility, management maintains strong internal controls, supported by formal policies and procedures that are communicated throughout OPPD. Management also maintains a staff of internal auditors who evaluate the adequacy of and investigate the adherence to these controls, policies and procedures. OPPD is committed to conducting business with integrity, in accordance with the highest ethical standards, and in compliance with all applicable laws, rules and regulations. OPPD has adopted a Code of Ethics for the Senior Executive and Financial Officers and the Controller, stating their responsibilities and standards for professional and ethical conduct.

Our independent auditors have audited the financial statements and have rendered an unmodified opinion as to the statements' fairness of presentation, in all material respects, in conformity with accounting principles generally accepted in the United States of America. During the audit, they considered OPPD's internal controls over financial reporting as required by generally accepted auditing standards.

The Board of Directors pursues its oversight with respect to OPPD's financial statements through the Audit Committee, which is comprised solely of non-management directors. The committee meets periodically with the independent auditors, internal auditors and management to ensure that all are properly discharging their responsibilities. The committee reviews the annual audit plan and any recommendations the independent auditors have related to the internal control structure. The Board of Directors, on the recommendation of the Audit Committee, engages the independent auditors who have unrestricted access to the Audit Committee.

W. Gary Gates

W. Gary Gates
President and Chief Executive Officer

Edward E. Easterlin
Vice President and Chief Financial Officer

Independent Auditors' Report

To the Board of Directors
Omaha Public Power District
Omaha, Nebraska

We have audited the accompanying financial statements of Omaha Public Power District (OPPD), which comprise the statements of net position as of December 31, 2012 and 2011, and the related statements of revenues, expenses, and changes in net position, and cash flows for each of the three years in the period ended December 31, 2012, and the related notes to the financial statements, which collectively comprise OPPD's financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to OPPD's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of OPPD's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of OPPD as of December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1 to the financial statements, in 2012, OPPD adopted new accounting guidance to conform to Government Accounting Standards Board Statements No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position*, and No. 65, *Items Previously Reported as Assets and Liabilities*. Our opinion is not modified with respect to this matter.

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the Management's Discussion and Analysis on pages 2 through 16 be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Deloitte & Touche LLP

DELOITTE & TOUCHE LLP

Omaha, Nebraska
March 21, 2013

Statements of Net Position
as of December 31, 2012 and 2011

ASSETS	2012	2011
	(thousands)	
CURRENT ASSETS		
Cash and cash equivalents	**$ 60,486**	$ 30,661
Electric system revenue fund	**-**	12,248
Electric system revenue bond fund	**56,960**	60,464
Electric system subordinated revenue bond fund	**6,440**	6,445
Electric system construction fund	**324,191**	192,427
NC2 separate electric system revenue fund	**13,827**	13,782
NC2 separate electric system revenue bond fund	**8,555**	8,504
NC2 separate electric system capital costs fund	**3,371**	3,819
Accounts receivable - net	**150,599**	125,213
Fossil fuels - at average cost	**46,485**	51,683
Materials and supplies - at average cost	**109,899**	101,610
Other (Note 2)	**28,883**	20,307
Total current assets	**809,696**	627,163
SPECIAL PURPOSE FUNDS - at fair value		
Electric system revenue bond fund - net of current	**60,484**	54,914
Segregated fund - debt retirement (Note 3)	**14,000**	48,000
Segregated fund - rate stabilization (Note 3)	**24,612**	-
Segregated fund - other (Note 3)	**34,819**	30,306
Decommissioning funds (Note 3)	**349,724**	336,891
Total special purpose funds	**483,639**	470,111
UTILITY PLANT - at cost		
Electric plant	**5,086,630**	4,943,363
Less accumulated depreciation and amortization	**1,844,664**	1,741,196
Electric plant - net	**3,241,966**	3,202,167
Nuclear fuel - at amortized cost	**100,765**	83,730
Total utility plant - net	**3,342,731**	3,285,897
OTHER LONG-TERM ASSETS (Note 2)	**200,247**	131,281
TOTAL ASSETS	**4,836,313**	4,514,452
DEFERRED OUTFLOWS OF RESOURCES		
Unamortized loss on refunded debt	**33,000**	20,820
Accumulated decrease in fair value of hedging derivatives (Note 9)	**502**	1,444
Total deferred outflows of resources	**33,502**	22,264
TOTAL ASSETS AND DEFERRED OUTFLOWS	**$4,869,815**	$4,536,716

See notes to financial statements

LIABILITIES	2012	2011
	(thousands)	
CURRENT LIABILITIES		
Electric system revenue bonds (Note 5)	$ 26,125	$ 29,620
Electric revenue notes - commercial paper series (Note 5)	150,000	-
NC2 separate electric system revenue bonds (Note 5)	2,865	2,765
Subordinated obligation (Note 5)	406	372
Accounts payable	91,758	82,638
Accrued payments in lieu of taxes	29,034	27,156
Accrued interest	39,366	35,229
Accrued payroll	31,830	29,337
NC2 participant deposits (Note 7)	8,926	9,939
Other (Note 2)	5,637	8,216
Total current liabilities	385,947	225,272
LIABILITIES PAYABLE FROM SEGREGATED FUNDS (Note 2)	31,684	26,242
LONG-TERM DEBT (Note 5)		
Electric system revenue bonds - net of current	1,502,375	1,284,890
Electric system subordinated revenue bonds	346,270	346,730
Electric revenue notes - commercial paper series	-	150,000
Minibonds	28,127	27,756
NC2 separate electric system revenue bonds - net of current	239,695	242,560
Subordinated obligation - net of current	442	847
Total long-term debt	2,116,909	2,052,783
Unamortized discounts and premiums	103,849	49,826
Total long-term debt - net	2,220,758	2,102,609
OTHER LIABILITIES		
Decommissioning costs	349,724	336,891
Other (Note 2)	13,390	15,219
Total other liabilities	363,114	352,110
COMMITMENTS AND CONTINGENCIES (Note 14)		
TOTAL LIABILITIES	3,001,503	2,706,233
DEFERRED INFLOWS OF RESOURCES		
Rate stabilization reserve (Note 8)	32,000	32,000
Debt retirement reserve (Note 8)	17,000	34,000
Uncollectible accounts reserve - off-system	5,000	5,000
Total deferred inflows of resources	54,000	71,000
NET POSITION		
Net investment in capital assets	1,380,992	1,435,789
Restricted	25,295	37,200
Unrestricted	408,025	286,494
Total net position	1,814,312	1,759,483
TOTAL LIABILITIES, DEFERRED INFLOWS AND NET POSITION	$4,869,815	$4,536,716

See notes to financial statements

Statements of Revenues, Expenses and Changes in Net Position

for the Three Years Ended December 31, 2012

	2012	2011	2010
OPERATING REVENUES		*(thousands)*	
Retail sales	**$ 869,906**	$ 852,678	$ 772,816
Off-system sales	**123,191**	159,732	184,374
Other electric revenues	**54,900**	29,352	29,160
Total operating revenues	**1,047,997**	1,041,762	986,350
OPERATING EXPENSES			
Operations and maintenance			
Fuel	**236,557**	276,030	252,278
Purchased power	**73,966**	64,079	40,282
Production	**228,559**	235,004	223,050
Transmission	**21,996**	18,351	14,225
Distribution	**37,073**	35,965	39,357
Customer accounts	**13,949**	14,024	14,213
Customer service and information	**16,360**	13,537	16,015
Administrative and general	**141,613**	132,526	121,537
Total operations and maintenance	**770,073**	789,516	720,957
Depreciation and amortization	**128,794**	126,077	123,193
Payments in lieu of taxes	**30,094**	28,217	27,851
Total operating expenses	**928,961**	943,810	872,001
OPERATING INCOME	**119,036**	97,952	114,349
OTHER INCOME (EXPENSES)			
Contributions in aid of construction	**13,066**	7,470	3,867
Reduction of plant costs recovered through contributions in aid of construction	**(13,066)**	(7,470)	(3,867)
Decommissioning funds - investment income	**12,833**	14,631	16,631
Decommissioning funds - reinvestment	**(12,833)**	(14,631)	(16,631)
Investment income	**2,041**	3,121	2,815
Allowances for funds used during construction	**14,234**	12,185	8,699
Products and services - net	**3,279**	2,896	2,720
Other - net (Note 10)	**8,864**	19,055	7,021
Total other income - net	**28,418**	37,257	21,255
INTEREST EXPENSE	**92,625**	89,149	87,177
NET INCOME BEFORE SPECIAL ITEM	**54,829**	46,060	48,427
SPECIAL ITEM (Note 11)	**-**	8,380	(8,380)
NET INCOME	**54,829**	54,440	40,047
NET POSITION, BEGINNING OF YEAR	**1,759,483**	1,705,043	1,664,996
NET POSITION, END OF YEAR	**$1,814,312**	$1,759,483	$1,705,043

See notes to financial statements

Statements of Cash Flows

for the Three Years Ended December 31, 2012

	2012	2011	2010
		(thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Cash received from retail customers	**$897,540**	$ 820,042	$ 821,041
Cash received from off-system counterparties	**107,733**	167,152	168,903
Cash received from insurance companies	**17,656**	7,000	-
Cash paid to operations and maintenance suppliers	**(626,679)**	(623,956)	(555,820)
Cash paid to off-system counterparties	**(59,940)**	(41,719)	(13,290)
Cash paid to employees	**(156,361)**	(147,173)	(128,784)
Cash paid for in lieu of taxes and other taxes	**(28,216)**	(27,853)	(24,894)
Net cash provided from operating activities	**151,733**	153,493	267,156
CASH FLOWS FROM CAPITAL AND RELATED FINANCING ACTIVITIES			
Proceeds from long-term borrowings	**560,881**	467,314	120,000
Principal reduction of debt	**(289,085)**	(348,694)	(46,182)
Interest paid on debt	**(106,411)**	(102,072)	(85,491)
Acquisition and construction of capital assets	**(178,785)**	(206,995)	(199,474)
Proceeds from NC2 participants	**2,848**	2,848	2,805
Contributions in aid of construction and other reimbursements	**13,293**	10,213	11,664
Acquisition of nuclear fuel	**(10,813)**	(15,057)	(25,578)
Net cash used for capital and related financing activities	**(8,072)**	(192,443)	(222,256)
CASH FLOWS FROM INVESTING ACTIVITIES			
Purchases of investments	**(860,586)**	(714,429)	(848,357)
Maturities and sales of investments	**743,528**	745,472	813,916
Purchases of investments for decommissioning funds	**(291,237)**	(297,537)	(369,587)
Maturities and sales of investments in decommissioning funds	**291,237**	297,537	369,587
Investment income	**3,222**	3,063	4,093
Net cash provided from (used for) investing activities	**(113,836)**	34,106	(30,348)
CHANGE IN CASH AND CASH EQUIVALENTS	**29,825**	(4,844)	14,552
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**30,661**	35,505	20,953
CASH AND CASH EQUIVALENTS, END OF YEAR	**$ 60,486**	$ 30,661	$ 35,505
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED FROM OPERATING ACTIVITIES			
Operating income	**$119,036**	$ 97,952	$ 114,349
Adjustments to reconcile operating income to net cash provided from operating activities			
Depreciation and amortization	**128,794**	126,077	123,193
Amortization of nuclear fuel	**-**	5,873	20,738
Changes in assets and liabilities			
Accounts receivable	**(25,849)**	(4,572)	(23,517)
Fossil fuels	**5,198**	14,334	(4,339)
Materials and supplies	**(8,289)**	(8,899)	(7,111)
Regulatory asset for FPPA	**3,237**	(35,345)	-
Accounts payable	**3,432**	8,770	(5,671)
Accrued payments in lieu of taxes	**1,878**	364	2,957
Accrued payroll	**2,493**	(4,218)	6,056
Accrued production outage costs	**-**	(24,840)	24,840
Debt retirement reserve	**(17,000)**	(24,000)	13,000
Other	**(61,197)**	1,997	2,661
Net cash provided from operating activities	**$151,733**	$ 153,493	$ 267,156
NONCASH CAPITAL ACTIVITIES			
Utility plant additions from outstanding liabilities	**$ 30,590**	$ 25,025	$ 39,678

See notes to financial statements

Notes to Financial Statements
as of December 31, 2012 and 2011,
and for the Three Years Ended December 31, 2012

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Business – The Omaha Public Power District (OPPD or Company), a political subdivision of the state of Nebraska, is a public utility engaged in the generation, transmission and distribution of electric power and energy and other related activities. The Board of Directors is authorized to establish rates. OPPD is generally not liable for federal and state income or ad valorem taxes on property; however, payments in lieu of taxes are made to various local governments.

Basis of Accounting – The financial statements are presented in accordance with generally accepted accounting principles (GAAP) for proprietary funds of governmental entities. Accounting records are maintained generally in accordance with the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission (FERC) and all applicable pronouncements of the Governmental Accounting Standards Board (GASB).

OPPD applies the accounting policies established in GASB Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989, FASB and AICPA Pronouncements*, and GASB Statement No. 65, *Items Previously Reported as Assets and Liabilities*. This guidance permits an entity with cost-based rates to include costs in a period other than the period in which the costs would be charged to expense by an unregulated entity if it is probable that these costs will be recovered through rates charged to customers. This guidance also permits an entity to defer revenues by recognizing liabilities to cover future expenditures. The guidance applies to OPPD because the rates of regulated operations are established and approved by the governing board.

If, as a result of changes in regulation or competition, the ability to recover these assets and to satisfy these liabilities would not be assured, OPPD would be required to write off or write down such regulatory assets and liabilities, unless some form of transition cost recovery continues through established rates. In addition, any impairment to the carrying costs of deregulated plant and inventory assets would be determined. There were no write-downs of regulatory assets in any of the three years in the period ended December 31, 2012.

Classification of Revenues and Expenses – Revenues and expenses related to providing energy services in connection with the Company's principal ongoing operations are classified as operating. All other revenues and expenses are classified as non-operating and reported as other income (expenses) on the Statements of Revenues, Expenses and Changes in Net Position.

Revenue Recognition – Electric operating revenues are recognized as earned. Meters are read and bills are rendered on a cycle basis. Revenues earned after meters are read are estimated and accrued as unbilled revenues at the end of each accounting period.

Cash and Cash Equivalents – The operating fund account is called the Electric System Revenue Fund (Note 3). Highly liquid investments for the Electric System Revenue Fund with an original maturity of three months or less are considered to be cash equivalents. Cash and cash equivalents in the Special Purpose Funds are reported as investments.

Accounts Receivable – Accounts Receivable includes outstanding amounts from customers and an estimate for unbilled revenues. An estimate is made for the Reserve for Uncollectible Accounts for retail customers based on an analysis of the aging of Accounts Receivable and historical write-offs net of recoveries. Additional amounts may be included based on the credit risks of significant parties. Accounts Receivable includes $41,415,000 and $36,898,000 in unbilled revenues as of December 31, 2012 and 2011, respectively. Accounts Receivable was reported net of the Reserve for Uncollectible Accounts of $1,020,000 and $774,000 as of December 31, 2012 and 2011, respectively.

Utility Plant – Utility plant is stated at cost, which includes property additions, replacements of units of property and betterments. Maintenance and replacement of minor items are charged to operating expenses. Costs of depreciable units of electric plant retirements are eliminated from electric plant accounts by charges, less salvage plus removal expenses, to the accumulated depreciation account. Electric plant includes both tangible and intangible assets. Intangible assets include the costs of software and licenses. Electric plant includes construction work in progress of $394,415,000 and $360,085,000 as of December 31, 2012 and 2011, respectively.

Electric plant balances as of December 31, 2011, activity for 2012 and balances as of December 31, 2012, were as follows (in thousands):

	2011	Additions	Retirements	2012
Electric plant	$4,943,363	$177,226	$(33,959)	$5,086,630
Less accumulated depreciation and amortization	1,741,196	137,446	(33,978)	1,844,664
Electric plant - net	$3,202,167	$ 39,780	$ 19	$3,241,966

Allowances for funds used during construction, approximating the current weighted average cost of debt, were capitalized as a component of the cost of utility plant. These allowances for both construction work in progress and nuclear fuel were computed at 4.3% for the years ended December 31, 2012 and 2010, and 4.2% for the year ended December 31, 2011.

The carrying amount of long-lived assets for impairment are periodically reviewed. An asset is considered impaired when the magnitude of the decline in service utility is significant and not part of the normal life cycle of the capital asset. Impaired capital assets that will no longer be used are reported at the lower of carrying value or fair value. Impairment losses on capital assets that will continue to be used are measured using a method that best reflects the dimininshed service utility of the capital asset. FCS assets were not considered impaired because the service utility has not been diminished and the extended outage is not unusual to the life cycle of a nuclear generating station. FCS is expected to return to service in 2013. There were no write-downs for impairments in any of the three years in the period ended December 31, 2012.

Contributions in Aid of Construction (CIAC) – Payments are received from customers for construction costs primarily relating to the expansion of the electric system. FERC guidelines are followed in recording CIAC, which direct the reduction of utility plant assets by the amount of contributions received toward the construction of utility plant. To comply with GASB Codification Section N50, *Nonexchange Transactions* (formerly GASB Statement No. 33, *Accounting and Financial Reporting for Non-exchange Transactions*), while continuing to follow FERC guidelines, CIAC is recorded as other income and offset by an expense in the same amount representing the recovery of plant costs. CIAC from participants for the capital costs of NC2 was $4,725,000 and $3,407,000 for the years ended December 31, 2012 and 2011, respectively. CIAC from NC2 participants was insignificant for the year ended December 31, 2010.

Depreciation and Amortization – Depreciation for assets is computed on the straight-line basis at rates based on the estimated useful lives of the various classes of property. Depreciation expense for depreciable property has averaged approximately 2.9% for the year ended December 31, 2012, and 2.8% for the years ended December 31, 2011 and 2010.

Amortization of nuclear fuel is based on the cost thereof, which is prorated by fuel assembly in accordance with the thermal energy that each assembly produces. Intangible assets are amortized over their expected useful life. Amortization of intangible assets, included within depreciation and amortization expense, was $4,669,000, $4,478,000 and $3,940,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

In 2009, NC2 was placed in commercial operation. Half of the output is sold under 40-year Participation Power Agreements (PPAs). Certain participants funded their share of construction costs with NC2 Separate Electric System Revenue Bonds. These participants are billed for the debt service related to these bonds. The amounts recovered for debt service for the electric plant construction and other costs are included in off-system sales revenues. The revenues related to principal repayment will equal related depreciation and other deferred NC2 expenses over the 40-year term of the PPAs. To maintain revenue neutrality in the interim years, a regulatory asset was established to equate expenses and the amount included in off-system sales revenues for principal repayment. This regulatory asset will increase annually until 2030. After 2030, as principal repayments exceed depreciation and other deferred expenses, the regulatory asset will be reduced annually by recognizing deferred depreciation and other deferred expenses until its elimination in 2049, which is the end of the initial term of the PPAs.

In 2004, the Board of Directors approved a change in the depreciation estimate for Fort Calhoun production plant assets to 2043, which is ten years beyond the term of Fort Calhoun Station's (FCS) current operating license. A regulatory asset was established for the difference in depreciation expense resulting from the use of the estimated economic life of the asset versus the license term. The reduction in depreciation expense will be recorded each year as a regulatory asset in deferred charges until 2033. The regulatory asset will be reduced through the recognition of depreciation expense over the assets' remaining economic life in the years 2034 through 2043.

Nuclear Fuel Disposal Costs – Permanent disposal of spent nuclear fuel is the responsibility of the federal government under an agreement entered into with the DOE. Under the agreement, there is a fee of one mill per kilowatt-hour on net electricity generated and sold from FCS. The spent nuclear fuel disposal costs are included in nuclear fuel amortization and are collected from customers as part of fuel costs. There were no nuclear fuel disposal costs for the year ended December 31, 2012. Nuclear fuel disposal costs were $1,124,000 and $4,073,000 for the years ended December 31, 2011 and 2010, respectively.

The agreement required the federal government to begin accepting high-level nuclear waste by January 1998; however, the DOE does not have a storage facility. In May 1998, the United States Court of Appeals confirmed the DOE's statutory obligation to accept spent fuel by 1998, but rejected the request that a move-fuel order be issued. In March 2001, OPPD, along with a number of other utilities, filed suit against the DOE in the United States Court of Federal Claims alleging breach of contract.

Notes to Financial Statements
as of December 31, 2012 and 2011, and for the Three Years Ended December 31, 2012

In 2006, the DOE agreed to reimburse OPPD for allowable costs for managing and storing spent nuclear fuel and high-level waste incurred due to the DOE's delay in accepting waste. Applications are submitted periodically to the DOE for reimbursement of costs incurred for the storage of high-level nuclear waste and any reimbursements are included in CIAC.

Nuclear Decommissioning – The Board of Directors has approved the collection of nuclear decommissioning costs based on an independent engineering study of the costs to decommission FCS. Based on cost estimates, inflation rates and fund earnings projections, no funding has been necessary since 2001. Decommissioning funds are reported at fair value. The decommissioning cost liability is adjusted for investment income and changes in fair value, resulting in no impact on net income. Investment income was $7,534,000, $8,873,000 and $9,898,000 for the years ended December 31, 2012, 2011 and 2010, respectively. The fair value of the decommissioning funds increased $5,299,000, $5,758,000 and $6,733,000 during 2012, 2011 and 2010, respectively. The present value of the total decommissioning cost estimate for FCS was $733,314,000 and $717,548,000 as of June 30, 2012 and 2011, respectively.

Regulatory Assets and Liabilities – Rates for regulated operations are established and approved by the Board of Directors. The provisions of GASB Statement No. 62 and GASB Statement No. 65 are applied, and under this guidance, regulatory assets are rights to additional revenues or deferred expenses, which are expected to be recovered through customer rates over some future period, and regulatory liabilities are reductions in earnings (or costs recovered) to cover future expenditures.

A Fuel and Purchased Power Adjustment (FPPA) was implemented in the rate structure in 2010. The Board of Directors authorized the use of regulatory accounting to maintain revenue neutrality by matching retail revenues attributed to fuel and purchased power costs with the actual costs incurred. As a result of the extended outage at FCS, additional fuel and purchased power expenses were incurred, which resulted in FPPA under-recoveries of $45,375,000 and $36,871,000 for the years ended December 31, 2012 and 2011, respectively. The FPPA regulatory assets were reduced for customer collections of $11,969,000 and FCS outage insurance recoveries of $36,643,000 in 2012.

The Regulatory Asset for FPPA, included in Other Current Assets, was $19,955,000 and $11,969,000 as of December 31, 2012 and 2011, respectively (Note 2). The Regulatory Asset for FPPA, included in Other Long-Term Assets, was $12,422,000 and $23,645,000 as of December 31, 2012 and 2011, respectively (Note 2). This regulatory asset represented the rights to additional revenues based on incurred expenses due to under-recoveries of fuel and purchased power costs.

Additional regulatory assets included in Other Long-Term Assets consist of deferred financing costs and other deferred expenses for FCS and NC2. In 2004, the Board of Directors approved a change in the depreciation estimate for FCS production assets to 2043, which is ten years beyond the term of the current operating license. In May 2009, NC2 was placed in commercial operation. As previously noted, certain NC2 expenses were deferred to maintain revenue neutrality from transactions with participants who funded their share of construction costs with NC2 Separate Electric System Revenue Bonds. In June 2012, the Board of Directors authorized the use of regulatory accounting for debt issuance costs because of new accounting standards which would have required these costs to be expensed in the period incurred. These costs will continue to be amortized over the life of the associated bond issues consistent with the rate methodology. In September 2012, the Board of Directors authorized the use of regulatory accounting for significant, unplanned operations and maintenance costs incurred at FCS to address concerns from the Nuclear Regulatory Commission (NRC) and enhance operations. These costs will be amortized over a ten-year period commencing with FCS's return to service.

The balances of the Regulatory Assets as of December 31, 2011, activity for 2012 and balances as of December 31, 2012, were as follows (in thousands):

	2011	Additions	Reductions	2012
Regulatory asset for FCS - Recovery Costs	$ -	$ 70,627	$ -	$ 70,627
Regulatory asset for FCS - depreciation	48,477	6,228	-	54,705
Regulatory asset for NC2	31,127	8,823	(2,883)	37,067
Regulatory asset for FPPA	35,614	45,375	(48,612)	32,377
Regulatory asset for financing costs	18,360	1,870	(2,964)	17,266
	$133,578	$132,923	$(54,459)	$212,042

Regulatory liabilities, which are deferred inflows of resources, consist of reserves for debt retirement, rate stabilization and uncollectible accounts from off-system sales. The Debt Retirement Reserve was established for the retirement of outstanding debt and to help maintain debt service coverage ratios at appropriate levels (Note 8). The Rate Stabilization Reserve was established to help maintain stability in OPPD's long-term rate structure (Note 8). The Reserve for Uncollectible Accounts from off-system sales was established to recognize a loss contingency for uncollectible accounts from off-system sales customers based on the greater of $5,000,000 or an estimate (as defined) considering the previous year's accounts receivable balances for off-system sales customers.

The balances of the Regulatory Liabilities as of December 31, 2011, activity for 2012 and balances as of December 31, 2012, were as follows (in thousands):

	2011	Additions	Reductions	2012
Debt Retirement Reserve	$34,000	$ -	$(17,000)	$17,000
Rate Stabilization Reserve	32,000	-	-	32,000
Reserve for Uncollectible Accounts from off-system sales	5,000	-	-	5,000
	$71,000	$ -	$(17,000)	$54,000

Accrued Production Outage Costs – Costs of major planned production outages with estimated incremental operations and maintenance expenses of $5,000,000 or more are accrued during the period after a station is returned to service until it is taken out of service for a planned outage. FCS started a major refueling and maintenance outage in April 2011. Outage activities were suspended to focus on flood mitigation efforts, but were resumed in September 2011. In December 2011, the NRC placed FCS into a special category of their inspection manual, Chapter 0350. This Chapter is for nuclear plants that are in extended shut-downs with performance deficiencies. Efforts are under way to satisfactorily address all performance concerns. Normal operations of FCS are expected to resume in 2013. The next major planned production outage is scheduled to begin eighteen months after FCS is returned to service. There were no accrued production outage costs as of December 31, 2012 and 2011.

Natural Gas Inventories and Contracts – Natural gas inventories are maintained for the Cass County Station. The weighted average cost of natural gas consumed is used to expense natural gas from inventories. OPPD is exposed to market price fluctuations on its purchases of natural gas. The Company may enter into futures contracts and purchase options to manage the risk of volatility in the market price of gas on anticipated purchase transactions (Note 9).

Net Position – Net position is reported in three separate components on the Statement of Net Position. Net Investment in Capital Assets is the net position share attributable to net utility plant assets reduced by outstanding related debt. Restricted is the share of net position that has usage restraints imposed by law or by debt covenants, such as certain revenue bond funds and segregated funds, net of related liabilities. Unrestricted is the share of net position that is neither restricted nor invested in capital assets.

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

Recent Accounting Pronouncements – In December 2010, GASB issued Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*. This statement is intended to enhance the usefulness of GASB's codification by incorporating certain accounting guidance issued by the Financial Accounting Standards Boards (FASB) and the American Institute of Certified Public Accountants (AICPA) that is applicable to state and local governments into GASB's authoritative literature. This statement is effective for reporting periods beginning after December 15, 2011, and was implemented in 2012. The implementation of this statement had no significant impact on OPPD's financial position, results of operations or cash flows.

In June 2011, GASB issued Statement No. 63, *Financial Reporting of Deferred Outflows of Resources, Deferred Inflows of Resources, and Net Position*. This statement provides financial reporting guidance for deferred outflows of resources and deferred inflows of resources, which are distinct from assets and liabilities. This statement also amends the net asset reporting requirements in Statement No. 34, *Basic Financial Statements–and Management's Discussion and Analysis–for State and Local Governments*, and other pronouncements by incorporating deferred outflows of resources and deferred inflows of resources into the financial statements. This statement was effective for reporting periods beginning after December 15, 2011, and was implemented in 2012. The implementation impacted the Statement of Net Position, as certain assets and liabilities were reclassified as deferred outflows or deferred inflows.

In March 2012, GASB issued Statement No. 65, *Items Previously Reported as Assets and Liabilities*. This statement establishes accounting and financial reporting standards that reclassify, as deferred outflows of resources or deferred inflows of resources, certain items that were previously reported as assets and liabilities. The requirements of this statement will improve financial reporting by clarifying the appropriate use of the financial statement elements to ensure consistency in financial reporting. This statement is effective for reporting periods beginning after December 15, 2012, and was implemented in 2012. The implementation impacted the Statement of Net Position, as certain assets and liabilities were reclassified as deferred outflows or deferred inflows. This changed total assets, as previously reported, from $4,510,896,000 to $4,514,452,000 and total liabilities from $2,751,413,000 to $2,706,233,000 as of December 31, 2011. The differences were due to the reclassification for deferred inflows and outflows.

In June 2012, GASB issued Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27*. The objective of this statement is to improve accounting and financial reporting for pensions. This statement requires governments to more comprehensively and comparably measure the annual costs of pension benefits. This statement also enhances accountability and transparency through revised and new note disclosures and required supplementary information. This statement is effective for reporting periods beginning after June 15, 2014. The impact of this statement on financial position and results of operations is in the process of being evaluated.

2. ASSETS AND LIABILITIES DETAIL BALANCES

Other Current Assets

The composition as of December 31 was as follows (in thousands):

	2012	2011
Regulatory asset for FPPA	$ 19,955	$ 11,969
Prepayments	4,948	4,369
Sulfur dioxide allowance inventory	2,799	2,580
Interest receivable	642	1,113
Commodity derivative instruments (Note 9)	416	91
Other	123	185
Total	$ 28,883	$ 20,307

Other Long-Term Assets

The composition as of December 31 was as follows (in thousands):

	2012	2011
Regulatory asset for FCS – Recovery Costs	$ 70,627	$ -
Regulatory asset for FCS – depreciation	54,705	48,477
Regulatory asset for NC2	37,067	31,127
Regulatory asset for financing costs	17,266	18,360
Regulatory asset for FPPA	12,422	23,645
Sulfur dioxide allowance inventory	1,625	3,250
Other	6,535	6,422
Total	$200,247	$131,281

Other Current Liabilities

The composition as of December 31 was as follows (in thousands):

	2012	2011
Unearned revenues	$ 2,441	$ 5,785
Payroll taxes and other employee liabilities	1,963	708
Deposits	804	832
Other	429	891
Total	$ 5,637	$ 8,216

Liabilities Payable from Segregated Funds

The composition as of December 31 was as follows (in thousands):

	2012	2011
Customer deposits	$ 24,293	$ 20,600
Customer advances for construction	3,413	2,164
Incurred but not presented reserve	2,310	2,177
Other	1,668	1,301
Total	$ 31,684	$ 26,242

Other Liabilities

The composition as of December 31 was as follows (in thousands):

	2012	2011
Unearned revenues	$ 9,219	$ 10,855
Capital purchase agreement	2,175	2,387
Workers' compensation reserve	1,344	1,345
Public liability reserve	199	111
Other	453	521
Total	$ 13,390	$ 15,219

3. FUNDS

Funds of OPPD were as follows:

Electric System Revenue Fund and NC2 Separate Electric System Revenue Fund – These funds are to be used for operating activities for their respective electric system. Cash and cash equivalents in the Electric System Revenue Fund are shown separately from investments on the Statement of Net Position.

Electric System Revenue Bond Fund, Electric System Subordinated Revenue Bond Fund and NC2 Separate Electric System Revenue Bond Fund – These funds are to be used for the retirement of their respective revenue bonds and the payment of the related interest and reserves as required. Investments with maturity dates within the next year are designated as current.

Electric System Construction Fund and NC2 Separate Electric System Capital Costs Fund – These funds are to be used for capital improvements, additions and betterments to and extensions of their respective electric system.

Segregated Fund – Debt Retirement – This fund is to be used for the retirement of outstanding debt and to assist in maintaining debt service coverage ratios at appropriate levels. Since there is no funding requirement for the Debt Retirement Reserve, this fund also may be used to provide additional liquidity for operations as necessary. The balance of the Debt Retirement Fund was $14,000,000 and $48,000,000 as of December 31, 2012 and 2011, respectively. As of February 28, 2013, $3,000,000 was transferred to the fund, which brought the balance to $17,000,000, the amount of the related reserve.

Segregated Fund - Rate Stabilization – This fund is to be used to assist in stabilizing rates through the transfer of funds to operations as necessary. Since there is no funding requirement for the Rate Stabilization Reserve, this fund also may be used to provide additional liquidity for operations as necessary. This fund was used to help finance higher fuel costs and unexpected energy purchases in 2011, due to the extended outage at FCS. Proceeds from the outage insurance policy and customer collections for prior year FPPA under-recoveries were used to partially replenish this fund in 2012. The balance of the Rate Stabilization Fund was $24,612,000 and $0 as of December 31, 2012 and 2011, respectively. The fund balance was returned to $32,000,000 in January 2013, after the receipt of additional proceeds from the outage insurance policy.

Segregated Fund - Other – This fund represents assets held for payment of customer deposits, refundable advances, certain other liabilities and funds set aside for terminal removal costs for NC2 and OPPD's self-insured health insurance plans (Note 6).

The balances of the funds at December 31 were as follows (in thousands):

	2012	2011
Segregated Fund - self-insurance	$ 5,106	$ 6,145
Segregated Fund - other	29,713	24,161
Total	$34,819	$30,306

Decommissioning Funds – These funds are for the costs to decommission FCS when its operating license expires. The Decommissioning Funds are held by an outside trustee in compliance with the decommissioning funding plans approved by the Board of Directors. The 1990 Plan was established in accordance with NRC regulations for the purpose of discharging the obligation to decommission FCS. The 1992 Plan was established to retain funds in excess of NRC minimum funding requirements based on an independent engineering study which indicated that decommissioning costs would exceed the NRC minimum requirements.

The balances of the funds at December 31 were as follows (in thousands):

	2012	2011
Decommissioning Trust - 1990 Plan	$267,278	$257,849
Decommissioning Trust - 1992 Plan	82,446	79,042
Total	$349,724	$336,891

4. DEPOSITS AND INVESTMENTS

Investments – Fair values of investments were determined based on quotes received from trustees' market valuation services. The weighted average maturity was based on the face value for investments.

As of December 31, investments were as follows (in thousands):

	2012		2011	
Investment Type	**Fair Value**	**Weighted Average Maturity (Years)**	**Fair Value**	**Weighted Average Maturity (Years)**
Cash	$ -	-	$ 8,935	-
Commercial paper	-	-	4,936	0.1
Money market	25,825	-	57,975	-
Mutual funds	186,842	-	174,121	-
U.S. agencies	538,450	1.4	480,469	1.2
U.S. treasuries	126,902	2.2	28,975	3.8
Corporate bonds	18,548	3.3	-	-
World bank security notes	-	-	10,460	0.1
Total	$896,567		$765,871	
Portfolio weighted average maturity		1.2		0.9

Interest Rate Risk – The investment in relatively short-term securities reduces interest rate risk, as evidenced by its portfolio weighted average maturity of 1.2 and 0.9 years as of December 31, 2012 and 2011, respectively. In addition, OPPD is a buy-and-hold investor, which minimizes interest rate risk.

Credit Risk – The investment policy is to comply with bond covenants and state statutes for governmental entities, which limit investments to investment-grade fixed income obligations. OPPD was in full compliance with bond covenants and state statutes as of December 31, 2012 and 2011.

Custodial Credit Risk – Bank deposits were entirely insured or collateralized with securities held by OPPD or by its agent in OPPD's name at December 31, 2012 and 2011. All investment securities are delivered under contractual trust agreements.

5. DEBT

The proceeds of debt issued are utilized primarily to finance the construction program.

Debt balances as of December 31, 2011, activity for 2012 and balances as of December 31, 2012, were as follows (in thousands):

	2011	Additions	Retirements	2012
Electric system revenue bonds	$1,314,510	$499,370	$(285,380)	$1,528,500
Electric system subordinated revenue bonds	346,730	-	(460)	346,270
Electric revenue notes – commercial paper series	150,000	-	-	150,000
Minibonds	27,756	514	(143)	28,127
NC2 separate electric system revenue bonds	245,325	-	(2,765)	242,560
Subordinated obligation	1,219	-	(371)	848
Total	$2,085,540	$499,884	$(289,119)	$2,296,305

Lien Structure – In the event of a default, subject to the terms and conditions of debt covenants, OPPD is required to satisfy all Electric System Revenue Bond obligations before paying second-tier bonds and notes which are Electric System Subordinated Revenue Bonds, Electric Revenue Notes – Commercial Paper Series and Minibonds. OPPD will pay the Subordinated Obligation after second-tier debt.

Electric System Revenue Bonds – These bonds are payable from and secured by a pledge of and lien upon the revenues of the Electric System, subject to the prior payment therefrom of the operations and maintenance expenses of the Electric System. The Electric System Revenue Bonds are the Senior Bonds.

Moody's Investors Service and Standard & Poor's Rating Services rated the Electric System Revenue Bonds as Aa1 and AA, respectively, in 2012 and 2011.

Outstanding Electric System Revenue Bonds as of December 31, 2012, were as follows (in thousands):

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2013 - 2014	Term	5.5%	$ 27,620
2003 Series A	2013	Serial	3.8%	7,000
2005 Series B	2017 - 2022	Serial	5.0%	17,740
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2013 - 2030	Serial	2.0% - 5.0%	140,465
2012 Series A	2023 - 2034	Serial	4.0% - 5.0%	139,480
2012 Series A	2035 - 2042	Term	5.0%	133,175
2012 Series B	2017 - 2034	Serial	3.0% - 5.0%	141,295
2012 Series B	2038 - 2046	Term	3.75% - 5.0%	85,420
Total				$1,528,500

Notes to Financial Statements
as of December 31, 2012 and 2011, and for the Three Years Ended December 31, 2012

Outstanding Electric System Revenue Bonds as of December 31, 2011, were as follows (in thousands):

Issue	Maturity Dates	Type	Interest Rates	Amount
1993 Series C	2012 - 2014	Term	5.5%	$ 44,820
2003 Series B	2012 - 2013	Serial	4.5% - 5.0%	27,260
2003 Series A	2012 - 2013	Serial	3.7% - 3.8%	14,000
2005 Series A	2012	Serial	3.55%	1,000
2005 Series B	2017 - 2022	Serial	5.0%	50,660
2006 Series A	2018 - 2044	Serial	4.25% - 4.75%	62,000
2006 Series A	2029 - 2046	Term	4.65% - 5.0%	138,000
2007 Series A	2018 - 2027	Serial	4.0% - 5.0%	108,705
2007 Series A	2029 - 2043	Term	4.75% - 5.0%	136,295
2008 Series A	2018 - 2028	Serial	4.6% - 5.5%	34,710
2008 Series A	2029 - 2039	Term	5.5%	70,290
2009 Series A	2023 - 2029	Serial	4.0% - 4.75%	25,700
2009 Series A	2030 - 2039	Term	5.0%	59,300
2010 Series A	2022 - 2041	Term	5.431%	120,000
2011 Series A	2014 - 2024	Serial	3.0% - 5.0%	143,375
2011 Series B	2023 - 2029	Serial	3.25% - 5.0%	34,570
2011 Series B	2031 - 2042	Term	4.0% - 5.0%	103,360
2011 Series C	2013 - 2030	Serial	2.0% - 5.0%	140,465
Total				$1,314,510

On February 1, 2012, a principal payment of $29,620,000 was made for the Electric System Revenue Bonds. On August 1, 2012, a principal payment of $8,850,000 was made for the call of the 1993 Series C term bonds due February 1, 2013. Term bonds are subject to call every six months. On November 1, 2012, a principal payment of $13,990,000 was made for the call of the 2002 Series B Electric System Revenue Bonds due on February 1, 2013. On October 10, 2012, OPPD issued 2012 Series A Electric System Revenue Bonds and Series B Electric System Revenue Bonds. The 2012 Series B Electric System Revenue Bonds were used for the refunding of portions of the 2005 Series B and 2006 Series A Bonds. The refunding reduced total debt service payments over the life of the bonds by $39,963,000 and resulted in an economic gain (difference between the present values of the old and new debt service payments) of $25,357,000.

On February 1, 2011, a principal payment of $28,465,000 was made for the Electric System Revenue Bonds. On August 1, 2011, a principal payment of $8,350,000 was made for the early call of the 1993 Series C term bonds due February 1, 2012. Term bonds are subject to call every six months. On June 15, 2011, OPPD issued 2011 Series A Electric System Revenue Bonds. On December 16, 2011, OPPD issued 2011 Series B Electric System Revenue Bonds and Series C Electric System Revenue Bonds. The 2011 Series A Electric System Revenue Bonds were used for the refunding of portions of the 2002 Series B and 2005 Series A Bonds. The refunding reduced total debt service payments over the life of the bonds by $10,554,000 and resulted in an economic gain of $9,642,000. The 2011 Series C Electric System Revenue Bonds were used for the refunding of 2003 Series A and the remaining portion of the 2005 Series A Bonds. The refunding reduced the total debt service payments over the life of the bonds by $15,329,000 and resulted in an economic gain of $11,238,000.

Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $426,125,000 as of December 31, 2012, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2003 Series A, 2005 Series B and 2006 Series A. Electric System Revenue Bonds, from the following series, with outstanding principal amounts of $459,850,000 as of December 31, 2011, were legally defeased: 1986 Series A, 1992 Series B, 1993 Series B, 2002 Series A, 2002 Series B, 2003 Series A and 2005 Series B. Defeased bonds are funded by government securities deposited in irrevocable escrow accounts. Accordingly, the bonds and the related government securities escrow accounts are not included in the Statement of Net Position.

OPPD's bond indenture, amended effective March 4, 2009, provides for certain restrictions, the most significant of which are:

- Additional bonds may not be issued unless estimated net receipts (as defined) for each future year equal or exceed 1.4 times the debt service on all Electric System Revenue Bonds outstanding, including the additional bonds being issued or to be issued in the case of a power plant (as defined) being financed in increments.
- The Electric System is required to be maintained by the Company in good condition. There is no longer a prescribed amount for replacements, renewals or additions to the Electric System.

Electric System Revenue Bond payments are as follows (in thousands):

	Principal	Interest
2013	$ 26,125	$ 68,180
2014	30,545	71,251
2015	40,465	69,448
2016	43,065	67,573
2017	45,900	65,636
2018-2022	223,225	296,387
2023-2027	226,160	245,093
2028-2032	268,565	185,733
2033-2037	251,040	122,250
2038-2042	290,255	47,555
2043-2046	83,155	6,457
Total	$1,528,500	$1,245,563

The average interest rate for Electric System Revenue Bonds was 4.8% for the years ended December 31, 2012 and 2010, and 4.9% for the year ended December 31, 2011.

Electric System Subordinated Revenue Bonds –These bonds are payable from and secured by a pledge of revenues of the Electric System, subject to the prior payment of the operations and maintenance expenses of the Electric System and the prior payment of the Electric System Revenue Bonds. The payment of the principal and interest on these bonds is insured by a municipal bond insurance policy.

The Electric System Subordinated Revenue Bonds include Periodically Issued Bonds (PIBs). Certain issues of the PIBs may be redeemed prior to maturity upon the death of the holder subject to certain conditions as outlined in the offering document.

Electric System Subordinated Revenue Bonds (PIBs) payments are as follows (in thousands):

	Principal	Interest
2013	$ -	$ 6,540
2014	-	6,540
2015	-	6,540
2016	-	6,540
2017	-	6,540
2018-2022	-	32,701
2023-2027	-	32,702
2028-2032	-	32,702
2033-2037	74,230	27,743
2038-2042	72,040	11,455
Total	$146,270	$170,003

Notes to Financial Statements
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Electric System Subordinated Revenue Bond payments for the 2007 Series AA are as follows (in thousands):

	Principal	Interest
2013	$ -	$ 8,901
2014	-	8,901
2015	-	8,902
2016	-	8,902
2017	-	8,902
2018-2022	6,000	44,042
2023-2027	34,000	40,658
2028-2032	58,000	29,971
2033-2037	85,000	12,713
2038	17,000	382
Total	$200,000	$172,274

The average interest rate for the Electric System Subordinated Revenue Bonds (PIBs and the 2007 Series AA) was 4.5% for each of the three years in the period ended December 31, 2012.

Electric Revenue Notes - Commercial Paper Series – The outstanding balance of Commercial Paper was $150,000,000 as of December 31, 2012 and 2011. The average borrowing rates were 0.2% for the year ended December 31, 2012, and 0.3% for the years ended December 31, 2011 and 2010. A Credit Agreement with Bank of America, N.A., includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper Notes.

Minibonds – Minibonds consist of current interest-bearing and capital appreciation minibonds. The minibonds may be redeemed prior to their maturity dates at the request of a holder, subject to certain conditions as outlined in the Minibond Official Statement. There were no Minibond maturities in 2012 other than redemptions for the annual put option. The average interest rates were 5.05% for each of the three years in the period ended December 31, 2012. The principal and interest on these bonds is insured by a municipal bond insurance policy.

The outstanding balances as of December 31 were as follows (in thousands):

Principal	**2012**	**2011**
2001 minibonds, due 2021 (5.05%)	$23,604	$23,711
Accreted interest on capital appreciation minibonds	4,523	4,045
Total	$28,127	$27,756

Subordinated Obligation – The subordinated obligation is payable in annual installments of $481,815, including interest at 9%, through 2014.

Credit Agreement – On September 21, 2010, a Credit Agreement was executed with the Bank of America, N.A., for $250,000,000 that will expire on October 1, 2013. The Credit Agreement includes a covenant to retain drawing capacity at least equal to the issued and outstanding amount of Commercial Paper notes. There were no amounts outstanding under this Credit Agreement as of December 31, 2012 and 2011.

NC2 Separate Electric System Revenue Bonds – Participation Power Agreements were executed with seven public power and municipal utilities for half of the output of NC2. The participants' rights to receive, and obligations to pay costs related to, half of the output is the "Separate System."

NC2 Separate Electric System Revenue Bond payments are as follows (in thousands):

	Principal	Interest
2013	$ 2,865	$ 11,607
2014	2,970	11,498
2015	3,080	11,381
2016	3,200	11,258
2017	3,330	11,128
2018-2022	18,825	53,382
2023-2027	23,375	48,695
2028-2032	29,450	42,460
2033-2037	37,255	34,441
2038-2042	43,510	24,158
2043-2047	52,450	12,370
2048-2049	22,250	1,069
Total	$242,560	$273,447

The payment of principal and interest on the 2005 Series A and 2006 Series A Bonds is insured by municipal bond insurance policies. The average interest rate for NC2 Separate Electric System Revenue Bonds was 4.8% for each of the three years in the period ended December 31, 2012.

Fair Value Disclosure – The aggregate carrying amount and fair value of long-term debt, including current portion and excluding unamortized loss on refunded debt as of December 31 were as follows (in thousands):

2012		2011	
Carrying Amount	Fair Value	Carrying Amount	Fair Value
$2,400,154	$2,875,955	$2,135,366	$2,265,351

The estimated fair value amounts were determined using rates that are currently available for issuance of debt with similar credit ratings and maturities. As market interest rates decline in relation to the issuer's outstanding debt, the fair value of outstanding debt financial instruments with fixed interest rates and maturities will tend to rise. Conversely, as market interest rates increase, the fair value of outstanding debt financial instruments will tend to decline. Fair value will normally approximate the carrying amount as the debt financial instrument nears its maturity date. The use of different market assumptions may have an effect on the estimated fair value amount. Accordingly, the estimates presented herein are not necessarily indicative of the amounts that bondholders could realize in a current market exchange.

6. BENEFIT PLANS FOR EMPLOYEES AND RETIREES

RETIREMENT PLAN

Plan Description – All full-time employees are covered by the Retirement Plan (Retirement Plan) as they are not covered by Social Security. It is a single-employer, defined benefit plan that provides retirement and death benefits to Retirement Plan members and beneficiaries. The Retirement Plan was established and may be amended at the direction of the Board of Directors and is administered by OPPD. Actuarial valuations are completed as of January 1 of each year. As of January 1, 2012, 1,674 of the 4,436 total participants were receiving benefits. Generally, employees at the normal retirement age of 65 are entitled to annual pension benefits equal to 2.25% of their average compensation (as defined) times years of credited service (as defined) under the Traditional provision (as defined). Under the Cash Balance provision (as defined), members can receive the total vested value of their Cash Balance Account at separation from employment. Employees were allowed to make a one-time irrevocable election to have benefits determined based on the Cash Balance provision instead of the Traditional provision. There were 88 members with the Cash Balance provision as of December 31, 2012. Effective January 1, 2013, most new employees will only be eligible for the Cash Balance provision.

Funded Status and Funding Progress – Employees contributed 6.2% of their covered payroll to the Retirement Plan for each of the three years in the period ended December 31, 2012. OPPD is obligated to contribute the balance of the funds needed on an actuarially determined basis.

The Present Value of Accrued Plan Benefits (PVAPB) is the present value of benefits based on compensation and service to the date of the actuarial valuation. This is the amount the Retirement Plan would owe participants if the Retirement Plan were frozen on the valuation date.

The PVAPB is presented in the table below based on the actuarial valuation as of January 1 (dollars in thousands):

	Actuarial Value of Assets	Present Value of Accrued Plan Benefits (PVAPB)	Under Funded PVAPB	Funded Ratio	Covered Payroll	Under Funded PVAPB as a Percentage of Covered Payroll
	(a)	(b)	(b-a)	(a/b)	(c)	((b-a)/c)
2012	$805,763	$985,638	$179,875	81.8%	$192,169	93.6%
2011	$771,588	$929,439	$157,851	83.0%	$187,285	84.3%
2010	$733,227	$854,121	$120,894	85.8%	$188,277	64.2%

The Actuarial Accrued Liability (AAL) is the present value of retirement benefits adjusted for assumptions for future increases in compensation and service attributable to past accounting periods. The funded ratio for the AAL was lower than the PVAPB because the AAL method assumes future compensation and service increases. The annual contributions to the Retirement Plan consist of the cost for the current period plus a portion of the Unfunded Accrued Liability.

The AAL is presented in the table below based on the actuarial valuation as of January 1 (dollars in thousands):

	Actuarial Value of Assets	Actuarial Accrued Liability (AAL)	Unfunded Accrued Liability (UAL)	Funded Ratio	Covered Payroll	UAL Percentage of Covered Payroll
	(a)	(b)	(b-a)	(a/b)	(c)	((b-a)/c)
2012	$805,763	$1,155,410	$349,647	69.7%	$192,169	181.9%
2011	$771,588	$1,094,909	$323,321	70.5%	$187,285	172.6%
2010	$733,227	$1,018,914	$285,687	72.0%	$188,277	151.7%

Annual Pension Cost and Actuarial Assumptions – The annual pension cost and annual required contribution (ARC) was $53,463,000, $47,585,000 and $42,045,000 for the years ended December 31, 2012, 2011 and 2010, respectively. Since the entire ARC was funded, there was no net pension obligation as of December 31, 2012 and 2011. Retirement Plan contributions by employees for their covered annual payroll were $11,517,000, $11,369,000 and $11,313,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

The Entry Age Normal (Level Percent of Pay) cost method was used to determine contributions to the Retirement Plan. Under this actuarial method, an allocation to past service and future service is made by spreading the costs over an employee's career as a level percentage of pay. The actuarial value of Retirement Plan assets was determined using a method that smoothes the effect of short-term volatility in the market value of investments over approximately five years. Cost-of-living adjustments are provided to retirees and beneficiaries at the discretion of the Board of Directors. Ad-hoc cost-of-living increases granted to retirees and beneficiaries are amortized in the year for which the increase is authorized by the Board of Directors. Except for the liability associated with cost-of-living increases, the unfunded actuarial accrued liability was amortized on a level basis (closed group) over 15 years. A 15-year fresh start was used for the valuation as of January 1, 2010, with future assumption changes, plan changes and actual gains or losses amortized over 15 years. The healthy mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011 and 2010. The disabled mortality table used was the Static Mortality Table for Annuitants and Non-Annuitants for 2012 and the RP-2000 Disabled Retiree Mortality Table for 2011 and 2010.

Other actuarial assumptions are presented in the table below based on the actuarial valuation as of January 1:

	2012	2011	2010
Investment return (discount rate)	7.75%	7.75%	8.00%
Average rate of compensation increase	5.20%	5.20%	5.20%
Ad-hoc cost-of-living adjustment	-	-	-

Other employee benefit obligations are provided to allow certain current and former employees to retain the benefits to which they would have been entitled under the Retirement Plan, except for federally mandated limits and to provide supplemental pension benefits. The related pension expense, fund balance and employee benefit obligation were not material for any of the three years in the period ended December 31, 2012.

DEFINED CONTRIBUTION RETIREMENT SAVINGS PLAN – 401(k)/457

OPPD sponsors a Defined Contribution Retirement Savings Plan – 401(k) (401k Plan) and a Defined Contribution Retirement Savings Plan – 457 (457 Plan). Both the 401k Plan and 457 Plan cover all full-time employees and allow contributions by employees that are partially matched by OPPD. The 401k Plan's and 457 Plan's assets and income are held in an external trust account in the employee's name. The matching share of contributions was $7,128,000, $7,143,000 and $7,279,000 for the years ended December 31, 2012, 2011 and 2010, respectively. The employer maximum annual match on employee contributions was $4,000 per employee for each of the three years in the period ended December 31, 2012.

POST EMPLOYMENT BENEFITS OTHER THAN PENSIONS

There are two separate plans for Other Post Employment Benefits (OPEB). OPEB Plan A provides post-employment health care and life insurance benefits to qualifying members. OPEB Plan B provides post-employment health care premium coverage for the Company's share to qualifying members who were hired after December 31, 2007.

OPEB Plan A

Plan Description – OPEB Plan A (Plan A) provides post employment health care benefits to retirees, surviving spouses, and employees on long-term disability and their dependents and life insurance benefits to retirees and employees on long-term disability. Health care benefits are based on the coverage elected by Plan A members. OPPD's Medical Plan becomes a secondary plan when the members are retired and eligible for Medicare benefits. As of January 1, 2012, 1,539 of the 3,860 total members were receiving benefits.

Funded Status and Funding Progress – Plan A members are required to pay a monthly premium based on the elected coverage and the respective premium cost share agreement at the time of retirement. OPPD contributes the balance of the funds needed on an actuarially determined basis.

The Actuarial Accrued Liability (AAL) is the present value of benefits attributable to past accounting periods.

The AAL is presented in the table below based on the actuarial valuation as of January 1 (in thousands):

	Actuarial Value of Assets	Actuarial Accrued Liability (AAL)	Unfunded Accrued Liability (UAL)	Funded Ratio	Covered Payroll	UAL Percentage of Covered Payroll
	(a)	(b)	(b-a)	(a/b)	(c)	((b-a)/c)
2012	$68,130	$380,426	$312,296	17.9%	$192,169	162.5%
2011	$51,274	$360,200	$308,926	14.2%	$187,285	164.9%
2010	$37,729	$316,629	$278,900	11.9%	$188,277	148.1%

Annual OPEB Cost and Actuarial Assumptions – The annual OPEB cost and ARC for OPEB Plan A was $30,698,000, $29,511,000 and $25,751,000 for the years ended December 31, 2012, 2011 and 2010, respectively. Accounting standards require

recognition of an OPEB liability on the Statement of Net Position for the amount of any unfunded ARC. Since the entire ARC was funded, there was no net OPEB obligation as of December 31, 2012 and 2011. Contributions by Plan A members were $2,819,000, $2,303,000 and $2,096,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2012, 2011 and 2010, were as follows:

- The pre-Medicare health care trend rates ranged from 8% initial to 5% ultimate for 2012 and 2011 and 9% initial to 5% ultimate for 2010.
- The post-Medicare health care trend rates ranged from 7.5% initial to 5% ultimate for 2012 and 2011 and 9% initial to 5% ultimate for 2010.
- The investment return (discount rate) used was 7.5% for 2012 and 2011 and 7.85% for 2010, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The average rate of compensation increase used for all three years was 5.2%.
- The actuarial cost method used was the Projected Unit Credit.
- Amortization for the initial unfunded AAL and OPEB Plan changes was determined using a period of 30 years and the increasing method at a rate of 3% per year.
- Amortization for all changes (including gains/losses, assumption and plan provisions) after the initial year were determined using a closed period of 15 years and the level dollar method.
- The mortality table used for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011 and 2010.

OPEB Plan B

Plan Description – OPEB Plan B (Plan B) provides post-employment health care premium coverage for the Company's share for retirees and surviving spouses and their dependents to qualifying members who were hired after December 31, 2007. Benefits are based on the coverage elected by the Plan B members and the balance in the member's hypothetical account, which is a bookkeeping account. The hypothetical accounts are credited with $10,000 upon commencement of full-time employment, $1,000 annually on the member's anniversary date and interest income at 5% annually. Plan B benefits are for the payment of OPPD's share of the members' health care premiums. Plan benefits will continue until the member and eligible spouse cease to be covered under OPPD's Medical Plan, the member's hypothetical account is depleted or Plan B terminates, whichever occurs first. Benefits are forfeited for any member who fails to retire or who retires but does not immediately commence payments. As of January 1, 2012, only 1 of the 440 Plan B members was receiving benefits.

Funded Status and Funding Progress – OPPD contributes funds needed on an actuarially determined basis. Members do not contribute to Plan B.

The AAL is presented in the table below based on the actuarial valuations as of January 1 (in thousands):

	Actuarial Value of Assets	Actuarial Accrued Liability (AAL)	Overfunded Accrued Liability (OAL)	Funded Ratio	Covered Payroll	OAL Percentage of Covered Payroll
	(a)	(b)	(a-b)	(a/b)	(c)	((a-b)/c)
2012	$3,507	$ 756	$2,751	463.9%	$33,193	8.3%
2011	$3,281	$ 486	$2,795	675.1%	$23,888	11.7%
2010	$3,098	$ 176	$2,922	1,760.2%	$18,494	15.8%

Annual OPEB Cost and Actuarial Assumptions – There was no ARC for OPEB Plan B for any of the three years in the period ended December 31, 2012. The annual OPEB cost was $96,000, $91,000 and $87,000 for the years ended December 31, 2012, 2011 and 2010, respectively. There was an OPEB net asset of $1,667,000 and $1,764,000 as of December 31, 2012 and 2011, respectively.

The actuarial assumptions and methods used for the valuations on January 1, 2012, 2011 and 2010 were as follows:

- The investment return (discount rate) used for all three years was 5.5%, which was based on OPPD's expected long-term return on assets used to finance the payment of plan benefits.
- The actuarial cost method used was Projected Unit Credit for all three years.

- Amortization for gains/losses was determined using a closed period of 15 years and the level dollar method.
- The mortality table for healthy participants was the Static Mortality Table for Annuitants and Non-Annuitants for 2012 and the RP-2000 Combined Healthy Mortality Table projected to the valuation date for 2011 and 2010.

SELF-INSURANCE HEALTH PROGRAM

Employee health care and life insurance benefits are provided to substantially all full-time employees. There were 2,110 and 2,170 full-time employees with medical coverage as of December 31, 2012 and 2011, respectively. An Administrative Services Only (ASO) Health Insurance Program is used to account for the health insurance claims. With respect to the ASO program, reserves sufficient to satisfy both statutory and OPPD-directed requirements have been established to provide risk protection (Note 3). Additionally, private insurance has been purchased to cover claims in excess of 125% of expected aggregate levels and $450,000 per member.

Health care expenses for full-time employees (reduced by premium payments from participants) were $23,107,000, $22,603,000 and $26,557,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

The total cost of life and long-term disability insurance for full-time employees was $1,015,000, $1,190,000 and $854,000 for the years ended December 31, 2012, 2011 and 2010, respectively.

The balance of the Incurred But Not Presented Reserve was $2,310,000, $2,177,000 and $2,221,000 as of December 31, 2012, 2011 and 2010, respectively.

Audited financial statements for the Retirement Plan, Defined Contribution Retirement Savings Plans and OPEB Plans may be reviewed by contacting the Pension Administrator at Corporate Headquarters.

7. NC2 PARTICIPANT DEPOSITS

NC2 Participants were given the option to provide their own funds or to use Separate Electric System Revenue Bonds to fund their share of construction and start-up costs. In addition, since commercial operation, Participants have provided funds for capital renewals and expenditures. This liability represents the amount that the Participants' funds, including interest, exceeded allocated costs. NC2 Participant deposits were $8,926,000 and $9,939,000 as of December 31, 2012 and 2011, respectively.

8. ADDITIONS TO AND UTILIZATIONS OF RESERVES

The Debt Retirement Reserve was used to provide additional revenues and funding for capital expenditures and debt retirement in the amount of $17,000,000 and $24,000,000 for the years ended December 31, 2012 and 2011, respectively. Revenues of $13,000,000 were transferred to the Debt Retirement Reserve to use in future years for the year ended December 31, 2010.

The Board of Directors approved a $4,200,000 expense in 2010 for 2011 wind energy purchases to limit the 2011 FPPA. The Rate Stabilization Reserve was used to offset the financial impact from this expense. Due to strong financial results, the Board approved the $4,200,000 replenishment of this reserve for 2010. There were no net revenue adjustments from changes to the Rate Stabilization Reserve for any of the three years in the period ended December 31, 2012.

9. DERIVATIVES

OPPD entered into natural gas futures contracts with the New York Mercantile Exchange (NYMEX) to hedge expected cash flows associated with purchases of natural gas for operations. As required by generally accepted accounting principles, OPPD's natural gas futures contracts were evaluated and determined to be effective hedges. Accordingly, the deferred cash flow hedges for the unrealized losses and the fair value of the commodity derivative instruments were reported on the Statement of Net Position.

There were futures contracts with NYMEX based on the notional amount of 280,000 and 600,000 Million Metric British Thermal Units (mmBtu) of natural gas with negative fair values and deferred cash outflows of $502,000 and $1,444,000 as of December 31, 2012 and 2011, respectively. The fair value and deferred cash outflows for these contracts were determined using published pricing benchmarks obtained through independent sources. All of these contracts will be settled based on the pricing point at Henry Hub on their respective expiration date. The accumulated decrease in fair value of hedging derivatives was reported in deferred outflows of resources.

The balance in the margin account of $918,000 was reported with the fair value of the derivative instruments. The net amount for commodity derivative instruments reported in other current assets was $416,000 and $91,000 as of December 31, 2012 and 2011, respectively (Note 2). There were realized losses of $1,176,000, $2,213,000 and $2,600,000 for the years ended December 31, 2012, 2011 and 2010, respectively. Realized gains or losses from effective hedges are included in fuel expense.

Information regarding the NYMEX natural gas contracts outstanding, along with the deferred cash outflows of the aggregate contracts by maturity dates, as of December 31, 2012, was as follows (dollars in thousands):

Effective Date	Maturity Date	Reference Rate	Notional Amount (mmBtu)	Fair Value/Change in Fair Value
Various	June 2013	Pay average $5.206/mmBtu	50,000	$ (85)
Various	July 2013	Pay average $5.503/mmBtu	80,000	(155)
Various	August 2013	Pay average $5.446/mmBtu	70,000	(130)
Various	June 2014	Pay average $5.578/mmBtu	10,000	(16)
Various	July 2014	Pay average $5.626/mmBtu	40,000	(66)
Various	August 2014	Pay average $5.670/mmBtu	30,000	(50)
		Total	280,000	$ (502)

Basis Risk – Basis risk is the risk that arises when variable rates or prices of a hedging derivative instrument and a hedged item are based on different reference rates. Location basis risk is created by purchasing natural gas at the Northern Natural Gas "Demarcation" pricing point and entering into the futures contract at the Henry Hub pricing point. Critical terms risk exists because the hedging instrument is a monthly transaction and the purchase of physical natural gas is typically a daily transaction. These two differences create the greatest amount of variation between the hedging instruments and the price paid for physical purchases.

Rollover Risk – Rollover risk is the risk that a hedging derivative instrument associated with a hedgeable item does not extend to the maturity of that hedgeable item. Rollover risk exists because the purchase of natural gas for the generation of electricity is an ongoing process whereas the hedges are only for the summer load months.

10. OTHER - NET

The composition for the years ended December 31 was as follows (in thousands):

	2012	2011	2010
Grants from FEMA	$5,082	$15,645	$4,593
Interest subsidies from the federal government	2,281	2,281	279
Health care subsidies from the federal government	617	1,031	1,967
Other	884	98	182
Total	$8,864	$19,055	$7,021

11. SPECIAL ITEM

OPPD provided notice to SPP in 2010 of its intent to change membership status from a transmission-owning member to a non transmission-owning member. A Special Item and related liability for the estimated fees of $8,380,000 to change membership status was recorded in 2010. The decision was made in 2011 to retain the same membership status because of several changes made by SPP including the approval of a 20-Year Integrated Transmission Plan with substantial benefits to OPPD's service area, the creation of a task force to address unintended consequences of the transmission cost allocation, and the planned move to an Integrated Marketplace in 2014. In 2011, the $8,380,000 liability for the estimated fees to change membership status was removed and a corresponding amount was recorded as a Special Item.

12. LOSSES AND RECOVERIES

Due to record snowfall in the Rocky Mountains and high water levels in the Missouri River Reservoirs, the United States Army Corps of Engineers released record amounts of water from dams along the Missouri River in 2011. This release of water caused flooding in areas near the Missouri River and impacted the operation of FCS. The reactor has been in cold shut-down since April 2011, which was the start of a planned refueling outage. In June 2011, outage activities were suspended to protect FCS facilities from rising river levels. In September 2011, water levels had receded enough to allow outage activities to resume and inspections for any flood damage to begin.

The Missouri River flood (Flood Event) impacted all of the coal and nuclear generating units and some transmission and distribution structures. Expenditures for the Flood Event were $11,493,000 and $47,525,000 for the years ended December 31, 2012 and 2011, respectively. These expenditures were partially offset by insurance recoveries of $1,910,000 and $11,536,000 for the years ended December 31, 2012 and 2011, respectively. Certain areas of the service territory were declared disaster areas which made OPPD eligible for total disaster assistance of $20,408,000 from FEMA. Grants from FEMA for this Flood Event and other qualifying disasters were recorded in non-operating income (Note 10). The balance of the FEMA receivable for the Flood Event was $19,941,000 and $15,605,000 as of December 31, 2012 and 2011, respectively.

Increased fuel costs and unexpected energy purchases were incurred due to the FCS extended outage, which resulted in FPPA under-recoveries for 2012 and 2011. Insurance recoveries of $36,643,000 were recognized in weekly indemnities from an insurance policy for outages caused by accidental property damage in 2012 at FCS. The insurance policy was acquired to mitigate the financial impact of qualifying outages, including additional fuel and purchased power expenses. The Board of Directors authorized the use of these insurance proceeds to reduce the FPPA regulatory asset, consistent with the objective of this policy. Insurance proceeds of $24,000,000 and $12,643,000 were received in January 2013 and October 2012, respectively. Insurance recoveries for property damage from a breaker fire at FCS of $1,750,000 were recognized for the year ended December 31, 2012. The balance of receivables from insurance companies was $25,432,000 and $4,536,000 as of December 31, 2012 and 2011, respectively.

The provisions of GASB Codification Section 1400.177, *Insurance Recoveries* (formerly GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries*) were followed, which provides that insurance recoveries should be recognized only when realized or realizable (i.e., when the insurer has admitted or acknowledged coverage). In addition, the Statement provides that impairment losses should be reported net of the associated insurance recovery when the recovery and the loss occur in the same year; and insurance recoveries reported in subsequent years should be reported as program revenue, non-operating revenue, or extraordinary item, as appropriate.

A summary of the impact on the financial statements for insurance recoveries for the years ended December 31 were as follows (in thousands):

	2012	2011
Increase in Other Electric Revenues	$23,080	$ -
Decrease in Operating Expenses	15,115	11,536
Increase in CIAC	2,108	-
Total	$40,303	$11,536

13. NUCLEAR REGULATORY COMMISSION OVERSIGHT

The NRC placed FCS into a special regulatory category of their inspection manual, Chapter 0350, in December 2011. This Chapter is for nuclear plants that are in extended shut-downs with performance issues. Efforts are under way to satisfactorily address all issues. Normal operations of FCS are expected to resume in 2013.

In August 2012, the Board of Directors authorized management to enter into a long-term operating service agreement with Exelon Generation Company, LLC, (Exelon) to provide operating and management support at FCS for 20 years. OPPD will remain the owner and licensed operator of the plant, while Exelon will provide the day-to-day operations management of the plant. The Exelon Nuclear Management Model will be used to improve and sustain performance at FCS.

Significant, unplanned recovery costs (Recovery Costs) are being incurred to resolve performance and operational concerns and to enhance future operations of FCS. Recovery Costs consist of operations and maintenance expenses incurred for the planning, execution and monitoring of restart and recovery activities. The Board of Directors authorized management to establish a regulatory asset for these Recovery Costs, which will be recovered through customer rates in future periods. These costs will be amortized over a ten-year period, commencing with FCS's return to service. Recovery Costs were $70,627,000 for the year ended December 31, 2012 (Note 2). Recovery Costs will continue to be deferred until FCS moves to a more favorable NRC regulatory category.

14. COMMITMENTS AND CONTINGENCIES

At December 31, 2012, the commitment for the uncompleted portion of construction contracts was approximately $35,671,000.

Power sales commitments that extend through 2027 were $112,972,000 at December 31, 2012. Power purchase commitments that extend through 2020 were $96,943,000 at December 31, 2012. These amounts do not include the Participation Power Agreements (PPAs) for NC2 or commitments for wind energy purchases.

There are 40-year PPAs with seven public power and municipal utilities (the Participants) for the sale of half of the 684.6-megawatt (MW) net capacity of NC2. The Participants have agreed to purchase their respective shares of the output on a "take-or-pay" basis even if the power is not available, delivered to or taken by the Participants. The Participants are subject to a step-up provision, whereby in the event of a Participant default, the remaining Participants are obligated to pay a share of any deficit in funds resulting from the default. There is an NC2 Transmission Facilities Cost Agreement with the Participants that addresses the cost allocation, payment and cost recovery for delivery of their respective power.

There is a 20-year PPA with the Nebraska Public Power District (NPPD) for a 16.8% share, or approximately 10 MW, of a 59.4-MW wind-turbine facility near Ainsworth, Nebraska. The commitment through 2025 under the PPA is $23,735,000 at December 31, 2012. OPPD is obligated, on a "take-or-pay" basis, under the PPA to make payments for purchased power even if the power is not available, delivered to or taken by OPPD. In the event another power purchaser defaults, OPPD is obligated, through a step-up provision, to pay a share of any deficit in funds resulting from the default.

There is a 20-year PPA with NPPD for a 31.25% share, or 25-MW, of an 80-MW wind-turbine facility near Bloomfield, Nebraska. The commitment through 2028 under the PPA is $10,464,000 at December 31, 2012. OPPD is obligated, on a "take-and-pay" basis, under the PPA to make payments for purchased power delivered to OPPD.

There is a 20-year PPA with Flat Water Wind Farm, LLC with an obligation for 100% of the output of the 60-MW wind-turbine facility near Humboldt, Nebraska. OPPD is obligated under the PPA to make payments for purchased power only when the power is made available to OPPD. The commitment through 2030 under the PPA is $162,000 at December 31, 2012.

There is a 20-year PPA with TPW Petersburg, LLC with an obligation for 100% of the output of the 40.5-MW wind-turbine facility near Petersburg, Nebraska. OPPD is obligated under the PPA to make payments for purchased power only when the power is made available to OPPD. The commitment through 2031 under the PPA is $354,000 at December 31, 2012.

Coal supply contracts that extend through 2015 with minimum future payments of $158,650,000 were in effect at December 31, 2012. Coal-transportation contracts that extend through 2013 with minimum future payments of $103,369,000 were in effect at December 31, 2012. These contracts are subject to price adjustments.

Contracts for uranium concentrate and conversion services are in effect through 2016 with estimated future payments of $43,400,000 at December 31, 2012. Contracts for the enrichment of nuclear fuel are in effect through 2026 with estimated future payments of $185,727,000 at December 31, 2012. Additionally, there are contracts through 2022 for the fabrication of nuclear fuel assemblies with estimated future payments of $47,015,000 at December 31, 2012.

In 2007, OPPD and the Metropolitan Community College (MCC) executed an Educational Services Agreement for $1,000,000 of educational services (as defined in the Agreement) over a ten-year period. If OPPD has not purchased the educational services by the end of the term, MCC shall have the right to extend the Agreement for an additional five years. As of December 31, 2012, the remaining commitment was $554,000.

Under the provisions of the Price-Anderson Act at December 31, 2012, OPPD and all other licensed nuclear power plant operators could each be assessed for claims and legal costs in the event of a nuclear incident in amounts not to exceed a total of $117,495,000 per reactor per incident with a maximum of $17,500,000 per incident in any one calendar year. These amounts are subject to adjustment every five years in accordance with the Consumer Price Index.

OPPD is engaged in routine litigation incidental to the conduct of its business and, in the opinion of Management, based upon the advice of General Counsel, the aggregate amounts recoverable or payable from OPPD, taking into account amounts provided in the financial statements, are not significant.

15. SUBSEQUENT EVENTS

On February 8, 2013, the Nebraska Power Review Board unanimously approved OPPD's application for the Prairie Breeze Wind Project. Construction of this 200.6-MW wind-energy project is scheduled to start in May 2013 and to be completed in January 2014. OPPD has agreed to buy energy from this project for 25 years at a predetermined, fixed price.

Statistics (Unaudited)

	2012	2011	2010	2009	2008	2007	2006	2005	2004	2003
Total Utility Plant (at year end) (in thousands of dollars)	**5,187,395**	5,027,093	4,865,417	4,678,449	4,561,815	4,259,501	4,166,997	3,656,433	3,363,909	3,224,851
Total Indebtedness (at year end) (in thousands of dollars)	**2,296,305**	2,085,540	2,011,969	1,937,704	1,902,403	1,866,472	1,565,807	1,133,171	894,020	939,972
Operating Revenues (in thousands of dollars)										
Residential	**362,105**	337,053	335,294	292,887	271,935	267,042	249,174	237,798	211,913	208,426
Commercial	**292,296**	274,102	284,400	265,668	238,496	228,060	213,314	204,314	194,684	189,820
Industrial	**197,225**	186,417	164,621	139,865	109,827	100,239	94,109	90,344	90,987	85,406
Off-System Sales	**123,191**	159,732	184,374	158,354	127,676	110,399	96,500	120,030	109,523	108,795
FPPA Revenue	**(3,237)**	35,345	269	—	—	—	—	—	—	—
Unbilled Revenues	**4,517**	(4,239)	1,232	7,449	3,391	1,742	2,527	630	(1,134)	4,086
Provision for Debt Retirement	**17,000**	24,000	(13,000)	13,000	20,000	27,000	(15,000)	—	(55,000)	(35,000)
Other Electric Revenues	**54,900**	29,352	29,160	22,743	16,648	15,771	36,204	13,436	15,342	11,541
Total	**1,047,997**	1,041,762	986,350	899,966	787,973	750,253	676,828	666,552	566,315	573,074
Operations & Maintenance Expenses (in thousands of dollars)	**770,073**	789,516	720,957	653,993	561,396	508,524	461,101	447,270	401,778	404,040
Payments in Lieu of Taxes (in thousands of dollars)	**30,094**	28,217	27,851	24,810	22,426	21,398	20,241	19,693	18,591	18,067
Net Operating Revenues before Depreciation and Amortization (in thousands of dollars)	**247,830**	224,029	237,542	221,163	204,151	220,331	195,486	199,589	145,946	150,967
Net Income (in thousands of dollars)	**54,829**	54,440	40,047	46,557	79,186	89,489	84,290	82,171	24,844	25,878
Energy Sales (in megawatt-hours)										
Residential	**3,595,316**	3,602,973	3,644,400	3,361,672	3,486,858	3,546,116	3,374,053	3,356,196	3,054,576	3,079,589
Commercial	**3,492,745**	3,481,459	3,777,092	3,672,982	3,758,853	3,750,634	3,577,436	3,535,036	3,369,713	3,347,214
Industrial	**3,670,346**	3,698,719	3,427,710	3,039,396	2,877,282	2,759,087	2,664,743	2,644,634	2,630,038	2,561,569
Off-System Sales	**3,671,978**	4,631,175	5,552,645	5,534,803	3,003,888	2,858,004	2,486,483	2,502,433	3,646,043	3,775,362
Unbilled Sales	**28,558**	(85,917)	(24,109)	74,416	50,374	13,858	9,628	21,285	6,890	61,165
Total	**14,458,943**	15,328,409	16,377,738	15,683,269	13,177,255	12,927,699	12,112,343	12,059,584	12,707,260	12,824,899
Number of Customers (average per year)										
Residential	**308,516**	308,412	303,374	299,813	296,648	293,642	289,713	282,310	275,854	270,579
Commercial	**43,589**	43,564	43,225	43,134	42,867	42,214	41,488	40,665	39,834	38,961
Industrial	**210**	206	154	151	142	134	132	133	135	127
Off-System	**35**	41	38	34	32	35	37	39	45	48
Total	**352,350**	352,223	346,791	343,132	339,689	336,025	331,370	323,147	315,868	309,715
Cents Per kWh (average)										
Residential	**10.12**	9.37	9.22	8.77	7.82	7.51	7.40	7.07	6.95	6.73
Commercial	**8.40**	7.89	7.54	7.29	6.36	6.07	5.99	5.77	5.76	5.69
Industrial	**5.38**	5.05	4.83	4.62	3.82	3.64	3.55	3.46	3.40	3.39
Retail	**7.94**	7.42	7.26	6.96	6.13	5.93	5.81	5.58	5.48	5.39
Generating Capability (at year end) (in megawatts)	**3,208.8**	3,222.7	3,224.7	3,223.9	2,548.8	2,548.8	2,544.1	2,542.5	2,540.5	2,540.5
System Peak Load (in megawatts)	**2,451.6**	2,468.3	2,402.8	2,316.4	2,181.1	2,197.4	2,271.9	2,223.3	2,143.8	2,144.8
Net System Requirements (in megawatt-hours)										
Generated	**12,855,389**	13,807,712	15,870,513	15,263,983	12,477,032	12,274,660	11,341,827	11,180,808	12,235,044	12,000,873
Purchased and Net Interchanged	**(1,529,643)**	(2,576,167)	(4,428,059)	(4,627,627)	(1,864,214)	(1,738,833)	(1,268,780)	(1,148,903)	(2,716,242)	(2,557,981)
Net	**11,325,746**	11,231,545	11,442,454	10,636,356	10,612,818	10,535,827	10,073,047	10,031,905	9,518,802	9,442,892

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