Transitions

Seattle City Light 2003

Annual Report



Seattle City Light 2 0 0 3

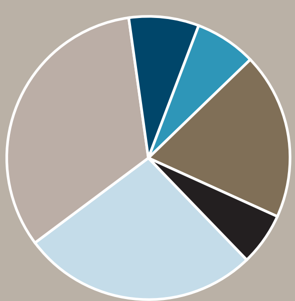
Annual Report

2003 HIGHLIGHTS

Financial (In Millions)	2003	2002	% Change
Total operating revenues	$ 739.0	$ 697.9	5.9
Total operating expenses	700.1	639.1	9.5
Net operating income	38.9	58.8	(33.8)
Investment income	3.8	10.1	(62.4)
Interest expense, net	(77.0)	(84.1)	(8.4)
Other income, net	0.1	0.3	(66.7)
Fees and grants	26.1	13.0	100.8
Net loss	$ (8.1)	$ (1.9)	326.3
Debt service coverage, prior lien bonds	1.56	1.61	(3.1)

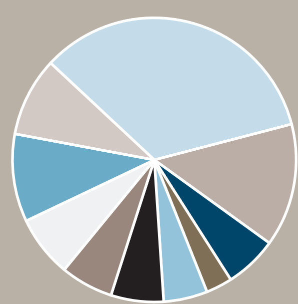
Energy	2003	2002	% Change
Total generation	6,098,753 MWh	6,891,659 MWh	(11.5)
Firm energy load	9,530,016 MWh	9,526,666 MWh	-
Peak load (highest single hourly use)	1,646 MW (December 30, 2003)	1,690 MW (January 29, 2002)	(2.6)
Average number of residential customers	330,979	327,127	1.2
Annual average residential energy consumption (includes unbilled revenue allocation)	8,921 kWh	9,311 kWh	(4.2)

2003 Operating Revenues **(in $1,000s = $739,005)**



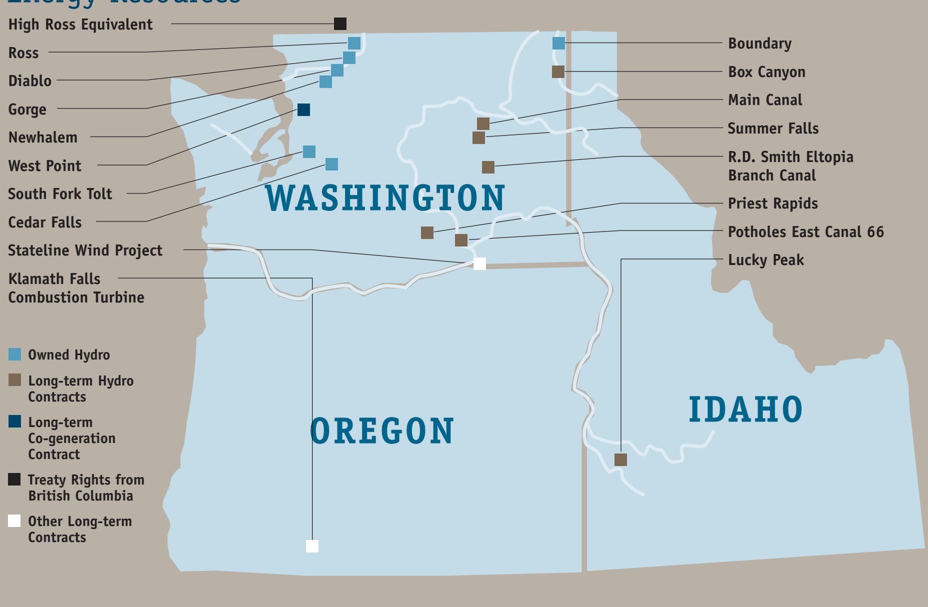
- 33% Commercial $243,237
- 27% Residential $199,392
- 19% Short-term Wholesale Power $137,651
- 8% Industrial $58,026
- 7% Governmental $51,578
- 6% Other $49,121

2003 Operating Expenses **(in $1,000s = $700,068)**

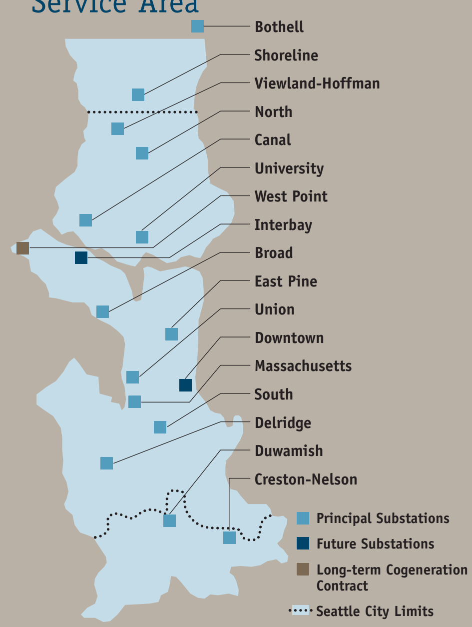


- 34% Long-term Power Purchases $240,505
- 14% Amortization of Deferred Power Costs $100,000
- 10% Depreciation $69,270
- 9% Taxes $61,606
- 7% Administrative & General $47,392
- 6% Short-term Wholesale & Other Power $45,372
- 6% Distribution $39,116
- 6% Customer Service & Conservation $42,083
- 5% Transmission $34,511
- 3% Generation $20,211

Energy Resources



Service Area



Message *from the* Superintendent

An introduction is in order.

I am Jorge Carrasco, Seattle City Light's new superintendent. Mayor Greg Nickels nominated me for that position in December 2003, and the Seattle City Council confirmed me early in 2004. This is my first superintendent's message for a City Light annual report.

2003 will prove to be an historic year for City Light. For the first time since the utility was created a century ago, its governance framework has been altered. More importantly, this change was part of an extraordinary alignment among the utility's overseers and stakeholders.

Jorge Carrasco
Seattle City Light
Superintendent

City Light emerged from the West Coast energy crisis with a strong consensus for change. Mayor Nickels appointed a blue-ribbon panel, which took a close look at the utility and recommended the creation of an independent board to act in an advisory capacity and focus exclusively on City Light policy issues.

The mayor adopted this recommendation, and the City Council concurred. The mayor and council then each appointed three board members. The Seattle City Light Advisory Board began meeting in June 2003, receiving presentations from every branch of the utility throughout the summer. Its first report and recommendations were published early in 2004.

I joined City Light on this wave of constructive change. Since then, we have made steady progress toward agreement about how the utility should move forward. I have been working with my executive team, the mayor, the City Council and the Advisory Board to establish clear goals and priorities for the utility. Beyond 2003, City Light will:

- Be a customer and community focused organization.
- Create an empowered, respectful, high-performance workplace that recognizes employees for their contributions to the Seattle City Light mission.
- Provide stable, competitively priced and environmentally sound electricity to customers.
- Create financial stability and flexibility to address industry challenges.

I look forward to reporting our progress on these goals in City Light's next annual report.

Transitions
Introduction

Transition, change and steady progress toward financial goals were the hallmarks of 2003 for Seattle City Light.

Gary Zarker, who led City Light for nine years, announced his retirement in February after the Seattle City Council indicated it would not reconfirm him as superintendent. Zarker remained on the job until May, when Jim Ritch, deputy superintendent for Finance and Administration, became acting superintendent.

Ritch kept City Light's financial team intact — including Finance Director Carol Everson and Financial Planning Manager Joe McGovern — and the utility continued to improve its financial position. In March, City Light redeemed $182.2 million in revenue anticipation notes (RANs) issued in March 2001. In November, it repaid another $125 million of RANs, borrowed in November 2002. At year end Seattle City Light had paid off all external debt remaining from the 2000-2001 energy crisis and owed $70 million to the City of Seattle cash pool. Net loss for the year was $8.1 million after recognizing $100 million of deferred 2001 power costs.

In August, City Light issued $251.85 million in long-term debt, with a true interest cost of 4.44 percent. Of the total, $136.17 million of the issue will finance capital improvement and conservation programs. The remaining $115.68 million was used to refinance 1993 bonds, achieving a $6.6 million net present value savings for customers. Moody's (Aa3) and Standard & Poor's investor services (A) maintained their credit ratings for City Light.

The year also introduced one of the most significant changes in City Light governance in its 100-year history. Selected by both the mayor and City Council, the six-member City Light Advisory Board began meeting in the summer. The Advisory Board was charged with providing financial advice and utility expertise to the superintendent, mayor and council.

One water year — which runs from Oct. 1 through Sept. 30 — ended well, and the next one started well during 2003. It took a very wet spring in 2003 to turn a bad water year into a mediocre one, bringing precipitation in City Light's watersheds up to 82 percent of normal. The 2003-2004 water year began with a bang. October rains brought floods to the Skagit, damaging property and devastating a record run of pink salmon. In spite of below-normal runoff in the spring and summer of 2003, City Light ended the year with net surplus wholesale power sales of $113.4 million.

In December, Seattle Mayor Greg Nickels announced his candidate for City Light superintendent. It was Jorge Carrasco, a man with 25 years of experience as a city manager, the head of a public water and wastewater utility and an executive for a private water-services company.

The year ended with anticipation of two important actions, expected in early 2004 — the confirmation of Carrasco as superintendent by the City Council and the initial report and recommendations of the City Light Advisory Board. Both are bound to have a significant impact on the future of Seattle City Light. The utility emerged from 2003 with its financial plan on track, poised to meet the goals it had set for itself during the energy crisis just two years earlier.

Short-Term Debt

2003

Perhaps nothing is more symbolic of City Light's recovery from the energy crisis than the repayment of revenue anticipation notes during 2003.

The combination of drought and high market prices meant that City Light had to borrow substantial sums to purchase power in 2001. To meet customer demand, the utility spent in excess of $500 million on power from the wholesale market in 2000-2001. The rates in place before the crisis assumed $20 million in net power market purchases. In response to this unexpected increase, the City Council raised retail rates four times in 2001 by a total of 58 percent. But even increases of this magnitude were insufficient to deal with the problem. In order to meet its cash requirements in 2001, City Light incurred short-term debt in the amount of $282.2 million by issuing two-year revenue anticipation notes ($182.2 million) and borrowing funds from the City of Seattle consolidated cash pool ($100 million). The utility replaced its existing debt to the cash pool in November 2002 by issuing a second one-year series of revenue anticipation notes ($125 million). The notes were issued at a true interest rate of 1.56 percent, far less than the projected rates of 3.5 to 4 percent that the utility would have had to pay on its loan from the city cash pool.

In March 2003, City Light redeemed the $182.2 million in RANs that it had issued in March 2001. In November, it redeemed the other $125 million in RANs, issued a year earlier. At that point, Seattle City Light had paid off all external debt remaining from the 2000-01 energy crisis.

At the end of 2003, City Light owed $70 million to the consolidated cash pool, which it continued to use for cash flow management. The utility attained a positive cash balance in the second quarter of 2004 and established a $30 million operating cash balance in the third quarter. By City Council resolution, passed in December 2001, the short-term debt payoff and $30 million positive balance will trigger a rate review process. The City will set new rates using new council-mandated financial policies that will explicitly address the higher level of risk City Light faces in the current electrical utility environment.

Resources

City Light's resource portfolio was robust and capable of providing sufficient power to its customers even under the worst water conditions. The blended, weighted average cost of power from its portfolio was $21.92 per megawatt-hour in 2003.

In 2003 City Light's resource mix included natural-gas combustion energy from the Klamath Falls cogeneration plant in southern Oregon and wind power from the Stateline Project in southeastern Washington. At 100 average megawatts, the Klamath plant provided about 5 percent of City Light's total supply. City Light increased its share of wind capacity from Stateline, beginning August 2002, from 50 to 100 megawatts. Those resources supplemented City Light's hydroelectric power, generated by the utility's own dams and federal power marketed by the Bonneville Power Administration (BPA). City Light conservation programs achieved more than 8 average megawatts of energy savings in 2003.

City Light's dams on the Skagit and Pend Oreille rivers produce, on average, almost half of the utility's total power supply. In normal weather conditions, these projects and City Light's long-term contracts produce significant surplus power for the wholesale market. Revenue from surplus sales helps hold down rates for City Light retail customers and has been one of the major factors in helping the utility recover from the energy crisis. The Power Management branch sold a large amount of energy in 2003. The Power Marketing division racked up gross surplus sales of $137.7 million which, along with purchases totaling $24.2 million, produced net surplus sales of $113.4 million.

In addition to record surplus sales, Power Management created new revenue for the utility by selling operating reserve services to several other utilities around the region. BPA requires every customer of its transmission business to maintain operating reserves to provide greater assurance of a reliable electric power grid. Utilities can provide these reserves themselves or buy them from BPA or a third party. Power Marketing staff negotiated new third-party operating reserve service agreements with several utilities, under which City Light would provide operating reserves to BPA on behalf of those utilities. The service began Oct. 1, and fourth-quarter revenue from these contracts totaled more than $1.4 million.

In 2003 City Light received 538 average annual megawatts of firm power from the federal system under a 2001 contract with BPA, as amended. About one-quarter of that power came in the form of a traditional block shaped to the difference between City Light's loads and owned resources. The rest of the BPA allotment comes to City Light as a fixed share of the federal system, for which City Light pays the same share of costs. City Light shares the risks with Bonneville when water is low but gains the benefits when water conditions improve. BPA audits the cost of this "slice" of the system each fiscal year. The 2003 fiscal year slice true-up audit resulted in a credit for City Light of $6,264,187, plus interest in the amount of $84,438, which will offset payments to BPA in 2004.

Governance

Seattle City Light has always been accountable directly to City government — the mayor and the City Council. The mayor appoints the superintendent and proposes rates and policies to the City Council, which oversees the utility in much the same way that it does all other city departments.

In the aftermath of the West Coast energy crisis, newly elected Mayor Greg Nickels appointed a blue-ribbon panel to look at City Light governance issues. The panel's recommendations included formation of a City Light Advisory Board that would provide the mayor, council and superintendent with independent expertise in the areas of risk management, finance and power markets, issue analysis, policy development, long-range planning and other areas particular to the electric utility industry.

The mayor and council accepted that recommendation. Established under the terms of City Ordinance 121059, the six-member Seattle City Light Advisory Board began meeting in June 2003. The board had a unique and imposing membership. Randy Hardy was a former administrator of the Bonneville Power Administration and superintendent of City Light. Jay Lapin was a former president of General Electric Japan. Carol Arnold was a utility attorney at Seattle's Preston, Gates and Ellis law firm. Sara Patton is executive director of the Northwest Energy Coalition. Don Wise is currently managing director of asset services at Metzler Realty Advisors, a German commercial real estate firm. Entrepreneur Maura O'Neill brought her experience with regional issues to the table.

The Advisory Board met throughout the summer, receiving presentations from every branch of the utility. Subjects covered in just the first three months of the board's existence included industry restructuring, environmental issues, conservation, finances, customer service, power resource strategy, distribution, power management, risk management and organization and staffing. The board's initial report and recommendations — setting both a short- and long-term direction for City Light — was published early in 2004.

Long-Term Borrowing

City Light issued new long-term debt in 2003 and also refinanced some outstanding debt to reduce long-term debt cost.

In August, City Light sold $251.85 million of long-term debt with a true interest cost of 4.44 percent. The utility will use $136.17 million of the issue to finance capital projects and conservation programs. The remaining $115.68 million was used to refinance outstanding debt, achieving a $6.6 million net present value savings for rate payers.

Both Moody's Investor Services and Standard & Poor's reaffirmed their strong ratings for City Light.

In maintaining its Aa3 credit rating for existing and new debt, Moody's cited City Light's "steady progress" in its recovery from the energy crisis. The agency also noted the utility's continued access to the City of Seattle's cash pool, the financial plan's conservative forecasts for water and energy prices, greatly reduced exposure to the wholesale power market, and "the fundamental longer-term strength" of the utility's low-cost, owned generation.

Standard & Poor's assigned an A rating to City Light's new revenue bonds and reaffirmed that rating on outstanding bonds. The rating reflected City Light's "fundamental credit strengths and progress toward full recovery by 2004."

Both agencies maintained a negative credit outlook for City Light, reflecting continued financial pressure during City Light's period of recovery from the 2000-2001 energy crisis and general uncertainty regarding electricity industry markets.

Nuts and Bolts

It was a busy year for Distribution, the City Light branch responsible for, among other things, the system's 14 major substations, 2,000 feeder lines, 3,100 miles of distribution circuit and 381,000 customer meters.

The branch completed phase one of its capacity plan, which includes a range of strategies and identifies the costs required to keep the distribution system ahead of future demand. Hot spots of development, including Interbay, South Downtown (SODO) and South Lake Union, are driving the plan. Amgen, a major biotechnology facility, came on line in Interbay in 2003, and Distribution is preparing to build a new Interbay substation by 2006, freeing up capacity at the existing Broad Street substation. That substation will serve South Lake Union as it grows as a biotech hub. South Lake Union eventually may need a new substation, and City Light began the property acquisition process in 2003.

Distribution continued planning in 2003 for major Seattle transportation projects, including Sound Transit's LINK light-rail project and the Seattle monorail. City Light completed engineering work on utility relocation along the light-rail alignment in South Seattle and on Pine Street in downtown Seattle. Preliminary engineering work was under way for the monorail's north corridor along 15th Avenue West.

In October, Jesse Krail left his post as deputy superintendent for Distribution to become deputy director of the Seattle Department of Transportation. Betty Tobin, a 24-year City Light employee, became acting deputy superintendent. One of her first challenges arose in December, when the most severe winter storm in several years lashed the area and cut power to more than 45,000 customers. City Light crews worked around the clock in freezing rain to restore power.

City Light's Generation branch completed work on generator unit 51 at the Boundary Dam powerhouse in 2003, part of an ongoing generator rehabilitation program at the facility. For the year, Generation achieved an 87.1 percent generator availability average, which surpassed the branch's goal for the year.

The Skagit Project welcomed Dave Bowers as its new manager in October, just in time for record flooding. Generation and Power Management held back in Ross Lake a part of a huge runoff to mitigate downstream flooding. The U.S. Army Corps of Engineers recognized City Light for its "major contribution ... to flood damage reduction in the Skagit River."

The heavy rains also triggered a massive rockslide in November on Highway 20 — the east-west highway just south of the Canadian border — that cut off road access between City Light's company towns of Newhalem and Diablo. Diablo was cut off from the outside world. Supplies and personnel could be taken in and out only by helicopter. The town remained isolated through the holidays and into the new year as the Washington State Department of Transportation worked to stabilize the slope and repair the roadway for its normal opening in April of 2004.

South Lake Union

The City of Seattle's vision of developing a biotechnology hub in the South Lake Union area means that City Light faces some key decisions about infrastructure investment. Almost all branches of the utility — along with many other city departments — were involved in the South Lake Union planning effort in 2003.

The planning challenge for City Light is to assure that there is enough capacity — not too much, not too little — to meet growth as it happens. Too much capacity means stranded costs for the utility and its ratepayers. Too little means low reliability and attendant economic impacts for customers. City Light's Distribution branch is taking a flexible approach for South Lake Union by looking at the system in its entirety. Creating more systemwide capacity will give City Light the flexibility to shift customer load among different substations.

The substation providing primary service to South Lake Union is now at capacity. A new substation in the Interbay neighborhood is in the planning stage. Reallocation of loads to this new substation will allow load increases in South Lake Union in the short term. In the long term, as the City's vision unfolds, City Light will probably need to build a new substation in the South Lake Union area.

As the Distribution branch worked on capacity issues, the Real Estate Services Division in the Finance and Administration branch began the process of acquiring a site for a South Lake Union substation. Meanwhile, the Distribution, Generation and Customer Services branches worked together to study the feasibility of an energy district for South Lake Union. In an energy district, a group of customers would develop a shared heating and cooling plant in the neighborhood, from which participating buildings would draw energy. The buildings would not need individual coolers and boilers, releasing more useable interior space. Phase one of the study was completed in 2003.

In concert with other City of Seattle efforts to make South Lake Union a sustainably developed area, City Light's Energy Management Services staff is working closely with developers and building owners to provide technical assistance and incentives toward "green" sustainable buildings.

City Light is prepared today to provide electrical service for much of the near-term growth that may occur at South Lake Union. It also stands ready to make the necessary investments to serve load as it occurs in five, ten or twenty years.

Regulation and Litigation

City Light continued to keep a wary eye on evolving national energy legislation in 2003. The previous year, City Light Director of External Affairs Jim Harding was instrumental in forming a coalition of consumer and utility interests primarily from the Northwest and Southeast. The effort helped kill a federal energy bill that would have imposed uniform rules on widely differing regional markets throughout the United States. In 2003, the coalition succeeded in getting language in both the House and Senate versions of the bill that limited the ability of the Federal Energy Regulatory Commission (FERC) to implement standard market design.

The bill that emerged from conference committee remained too costly and controversial to be brought to a vote in 2003. But the provisions limiting FERC remained intact. The coalition has slowed down the FERC's implementation calendar and undermined its attempt to effect radical change in the region's unique hydroelectric system.

Whether the issue is standard market design or creation of a regional transmission organization, City Light continues to favor solutions that fit the Northwest's unique energy identity rather than the FERC's ideology.

Another FERC decision affecting City Light in 2003 was the decision to deny refunds to Northwest utilities that had paid enormous prices for power during the 2000-2001 energy crisis. In December, Mayor Greg Nickels announced that the City of Seattle, having exhausted all available administrative processes, would seek action in federal court to collect the refunds.

"Federal regulators cost our customers millions of dollars because they failed to police the electricity market in the West," Nickels said.

City Light's refund claim of $282 million is one of several claims, including Snohomish County Public Utility District, the Port of Seattle, Tacoma Power and PacifiCorp, that have been denied in various rulings by the FERC during the past two years. The case is scheduled to be heard beginning late in 2004 in the Ninth Circuit Court in San Francisco.

Another court case made headlines in 2003. The Washington State Supreme Court ruled in November that the City of Seattle imposed an unlawful tax in 1999 when it shifted streetlight costs to City Light customers, in effect forcing them to subsidize the City's general fund. Following the decision, streetlight costs — about $6 million per year — reverted immediately to the general fund. The City's budget process was nearly complete at the time of the ruling, and officials proposed a temporary strategy to repay City Light for streetlight costs. The state Supreme Court remanded the case to King County Superior Court, which will rule on the required remedies.

Environmental Excellence

Water for fish, power for people — City Light's commitment to that doctrine of coexistence was never more apparent than in 2003, when the utility achieved several significant environmental accomplishments.

City Light earned recognition from the National Hydropower Association (NHA) for its role as an exceptional river steward. The NHA honored the utility in its fifth annual "Outstanding Stewardship of America's Rivers" report, which showcases hydro companies that excel in habitat enhancement, environmental restoration, recreational improvement, mitigation and fish passage. City Light, the report said, spent more than two decades working with agencies, tribes and conservation groups to protect salmon runs and preserve wildlife habitat on the river. Those efforts resulted in a 700 percent increase in the chum salmon population, and a recent healthy run of fall Puget Sound chinook, which are listed as threatened under the federal Endangered Species Act.

"The 2003 Outstanding Stewardship of America's Rivers winners exemplify the hydro industry's success in balancing power generation with environmental stewardship and recreational enhancement," said NHA President John Suloway.

In February, City Light's bold programs addressing climate change earned the City of Seattle a 2003 International Climate Protection Award from the federal Environmental Protection Agency (EPA). The EPA established its Climate Protection Award program in 1998 to recognize exceptional leadership, personal dedication and technical achievements in protecting the climate.

The award recognized Seattle for City Light's commitment to meeting all of its growth in energy demand through renewable resources and conservation. That policy resulted in the largest contract for wind power of any public utility in the country and reinforced the region's oldest and most effective conservation program, one of the leading programs in the nation. It also honored City Light's initiative to mitigate all greenhouse-gas emissions from any fossil-fuel-based power it uses, making City Light the first electric utility in the country committed to being climate neutral.

Earlier in the year, City Light implemented its first contract under the greenhouse-gas mitigation program. The contract promotes the use of industrial waste products such as fly ash and furnace slag as replacements for traditional materials used in cement. Processing raw materials for cement creates huge amounts of greenhouse gases that by some estimates account for 7 percent of worldwide human-caused greenhouse-gas emissions. By substituting waste materials that would otherwise go to landfills, cement producers and users can gain nearly a pound-for-pound reduction in emissions.

In May, the Low Impact Hydropower Institute (LIHI) certified City Light's Skagit Project as low-impact hydropower. The Skagit is the only project in Washington state and the first large hydro project in the nation to be certified. The Skagit Project successfully completed LIHI's rigorous application process, which includes public comment, review by an independent technical consultant, consultations with state and federal natural resource agencies, and evaluation by the LIHI governing board, including leaders in the river conservation and renewable energy fields. The board's vote to certify the Skagit was unanimous.

Certification as low impact means the facility is well sited, well operated, exceeds current legal requirements, and meets other defined environmental qualities. Certification from the institute also qualifies the power produced at the Skagit for participation in many green power programs as well as the Leadership in Energy and Environmental Design (LEED) building certification.

The salmon runs on the Skagit are testimony to City Light's stewardship. In the fall of 2003, one year after the largest chum run in the Skagit since 1917, pink salmon swarmed into the river in record numbers. An estimated two million pinks returned to the Skagit to spawn. But nature can sometimes overwhelm even the most careful resource management. Serious flooding in October, at the peak of the run, killed fish and wiped out untold numbers of eggs. The damage to the pink salmon population will not be known until the next run in fall 2005.

Conservation

The Customer Services branch is responsible for the utility's direct customer services, including Seattle City Light's conservation programs. Conservation has been a priority resource for City Light since 1977. The City of Seattle's Earth Day resolution (2000) and the utility's own strategic resources plan (2001) mandate that the utility meet all load growth over the next decade (2001-2011) through conservation and new renewable resources. With a well-established conservation program and load growth slowed by a sluggish economy, City Light finished 2003 well ahead of the pace necessary to achieve the overall goal.

BPA and City Light continued their conservation partnership that was renewed in 2002. Through the Conservation Augmentation Agreement, Bonneville paid City Light $10.7 million in 2003. City Light anticipates a minimum of 7.76 average megawatts of energy savings for federal fiscal year 2003-2004.

The commercial and industrial sectors provide City Light's greatest opportunities for energy conservation, and savings realized in those sectors amounted to 4.97 average megawatts in 2003. The slight drop-off from last year's 5.83 average megawatts reflected a slower economy and a poorer climate for energy-efficiency investments by large businesses. Still, City Light was involved with 235 customer contracts among large companies, institutions and governments within the service territory. City Light's energy-management field staff experts provided technical assistance and aggressive new construction and retrofit programs for lighting, heating and cooling systems, and industrial processes.

City Light's community conservation programs — aimed at residential customers, multifamily building owners and small businesses — realized 1.48 average megawatts of savings in 2003. The programs provide financial incentives for multifamily retrofits and new construction, small commercial lighting retrofits, resource-efficient clothes washers and low-income residential conservation. In 2003, City Light was involved in 52 new multifamily construction projects, 220 multifamily retrofits and 213 projects with small businesses. The utility provided WashWise rebates to 4,803 customers.

Total 2003 energy savings from new and prior participants for all sectors was enough to power 86,100 Seattle homes for one year. The resulting reduction in greenhouse-gas emissions was the equivalent of removing 32,500 vehicles from the region's roads for 13 years.

The Neighborhood Power Project targets a different neighborhood each year to promote resource conservation. Focusing on Seattle's Ballard neighborhood in 2003, City Light performed 189 "green" audits for residential customers and distributed 15,848 compact fluorescent light bulbs to the community.

Meanwhile, Seattle Green Power, City Light's own green power program, increased to almost 4,000 subscribers who make voluntary payments in addition to their regular bills in support of clean energy with no greenhouse-gas emissions. The program funded the installation of nine solar power systems at schools and other public facilities and supported other renewable energy projects such as dairy waste-to-energy and small wind turbines.

City Light's conservation program earned national recognition in 2003, receiving an Exemplary Program designation from the American Council for an Energy Efficient Economy.

Customer Service

In 2003, the Customer Services branch continued to aggressively address issues identified in 2001 and 2002 following the startup of the utility's new billing system. That billing system, coinciding with the energy crisis, four rate increases and a new, third-tier rate, posed enormous challenges for those reading meters, issuing bills and resolving bill disputes among City Light's 365,000 total customers.

A six-point business plan brought stability to the billing system. The goals were to eliminate backlogs, perform more thorough reviews of bills before they went out, develop new business practices, reduce estimated meter readings, and create an internal audit program for the computerized billing process.

By early 2003, staff had eliminated all backlogs in bill validation and service orders, resulting in better service-connection response times and fewer bills requiring adjustments. In 2003, City Light completed 93 percent of its service connections within five days of the original request.

Conclusion

In 2002, for the first time in 74 years, City Light did not offer public tours of its Skagit River hydroelectric project. The tour season was cancelled in the wake of the September 11, 2001, terrorist attacks on the United States. During the hiatus, City Light redesigned the tours to address security issues, and they resumed for their 75th anniversary in 2003.

J.D Ross, City Light superintendent from 1911 to 1939, began Skagit tours for Seattle citizens in 1928. Ross wanted to generate continued voter support and funding for Skagit Project construction, as well as showcase the beauty and recreational opportunities of the North Cascades. Today, the Skagit Project stands as a powerful symbol of City Light: public power and energy independence for Seattle, in harmony with the environment. The dams represent Seattle's energy past, present and future.

But the Skagit dams are practical as well as symbolic. With City Light's Boundary Dam on the Pend Oreille River, they are a major source of inexpensive, nonpolluting power for 750,000 people. Equally important, publicly-owned hydroelectric power has become embedded in the character of Seattle and the Pacific Northwest — one of those icons, like chinook salmon and Mount Rainier, that are a part of our Northwest religion.

Today, J.D. Ross and his legacy are a source of inspiration as Seattle and the Pacific Northwest confront a new set of challenges — the recovery from the West Coast energy crisis, endangered salmon runs, global climate change and continued efforts to deregulate the industry. As 2003 ended, City Light was poised to face the future with new leadership and recovered financial strength, eager to rekindle the sense of pride embodied in its Skagit legacy.

INDEPENDENT AUDITORS' REPORT

Superintendent
City of Seattle - City Light Department
Seattle, Washington

We have audited the accompanying balance sheets of the City of Seattle - City Light Department (the "Department") as of December 31, 2003 and 2002, and the related statements of revenues, expenses, and changes in equity and of cash flows for the years then ended. These financial statements are the responsibility of the Department's management. Our responsibility is to express an opinion on the financial statements based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Department as of December 31, 2003 and 2002, and the changes of its equity and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As described in Note 1 to the financial statements, during 2003, the Department changed its method of presenting certain power sale and purchase transactions related to the adoption of Emerging Issues Task Force ("EITF") Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes" as Defined in EITF Issue No. 02-03*.

The management's discussion and analysis on pages 18 through 25 is not a required part of the basic financial statements but is supplementary information required by the Governmental Accounting Standards Board. We have applied certain limited procedures, which consisted principally of inquiries of management regarding the methods of measurement and presentation of the supplementary information. However, we did not audit the information and express no opinion on it.

Deloitte & Touche LLP

Deloitte & Touche LLP
Seattle, Washington
May 21, 2004

MANAGEMENT'S DISCUSSION AND ANALYSIS - DECEMBER 31, 2003

The following discussion and analysis of the financial performance of the City of Seattle - City Light Department (the "Department") provides a summary of the financial activities for the year ended December 31, 2003. This discussion and analysis should be read in combination with the Department's financial statements, which immediately follow this section.

RESULTS OF OPERATIONS

Condensed Revenues and Expenses

Year ended December 31,	2003	2002
Operating revenues	$739,005,298	$697,892,243
Nonoperating revenues	3,849,386	10,467,972
Total revenues	742,854,684	708,360,215
Operating expenses	700,067,504	639,136,563
Nonoperating expenses	77,054,688	84,057,713
Total expenses	777,122,192	723,194,276
Capital contributions	22,089,096	10,631,017
Grants	4,044,558	2,337,759
Net loss	$ (8,133,854)	$ (1,865,285)

Net Loss–The Department recorded a net loss of $8.1 million in 2003, an increase of $6.2 million from the $1.9 million loss experienced in 2002. Expenses in both 2002 and 2003 included the amortization of $100 million in power costs deferred from 2001. Without these noncash charges, net income would have been $98.1 million in 2002 and $91.9 million in 2003.

Water conditions in the Northwest region were again below normal in 2003, depressing the Department's wholesale revenues relative to the expected levels. Operating revenues increased by $41.1 million from 2002 to 2003, but certain elements of this increase were offset by corresponding increases in operating expenses, which were $60.9 million above the 2002 level. Net nonoperating expenses were virtually unchanged from the prior year. Contributions and grants totaled $26.1 million in 2003, a doubling of the amount realized in 2002.

OPERATING REVENUES

Operating revenues totaled $739.0 million in 2003, an increase of $41.1 million (5.9%) from the level of $697.9 million recorded in the prior year. Revenue from retail sales were $10.2 million lower than in 2002, with the decline concentrated in the residential sector. Wholesale revenues were $49.3 million higher than in 2003, but the increase was partially offset by corresponding increases in the cost of wholesale purchases. Other revenues increased by $2.0 million, from $13.0 million in 2002 to $15.0 million in 2003.

Retail Revenues–Revenue of $552.2 million from retail power sales within the Department's service territory was 1.8% lower than the $562.4 million realized in 2002. Revenue from residential customers totaled $199.1 million, a reduction of $12.9 million (6.1%) from the prior year. The drop in residential revenue reflects a decrease of 4.3% in energy consumption in the residential class and a reduction of 1.9% in the average rate billed. Temperatures in the first quarter of 2003 were higher than in the corresponding period of 2002, which had the effect of reducing consumption for residential space heating. Reductions in consumption are more likely to occur in the higher-priced second and third residential rate blocks, thus lowering the average rate paid. In addition, effective June 14, 2002, the Seattle City Council reduced the residential third-block rate and increased the consumption threshold at which the third-block rate began to apply. Revenue from commercial customers increased by $5.3 million (2.2%), while industrial revenue showed an offsetting reduction of $5.5 million (8.7%). Revenue from governmental customers increased by $0.5 million (1.0%). Estimated unbilled revenue increased by $2.4 million from year-end 2002 to 2003, reflecting the fact that temperatures in November and December 2003 were lower than in the same period of 2002. Retail revenues were also reduced by a one-time noncash charge of $3.7 million needed to correct an overstatement of retail revenue in prior periods that was identified in 2003.

Wholesale Revenues–Revenue from short-term wholesale power sales was $137.7 million, an increase of $35.6 million (34.8%) from the prior year. The increase in revenue from 2002 to 2003 is attributable to an increase in the price at which wholesale energy was sold, from an average of $24.27 per megawatt hour ("MWh") in 2002 to $37.29 per MWh in 2003. The amount of wholesale energy sold actually decreased by 8.3%, from 4,647,945 MWh in 2002 to 4,262,041 MWh in 2003. Revenue from wholesale sales, net of the cost of wholesale purchases, totaled $113.4 million in 2003, an increase of $23.8 million from the $89.6 million in net revenue realized in 2002.

***Other Power-Related Revenue*–**The Department derives revenue from a number of other power-related activities, including the delivery of power under seasonal exchanges, the sale of capacity, the sale of conservation savings to the Bonneville Power Administration ("Bonneville"), and the sale of transmission basis services. Revenues from these activities increased from $20.4 million in 2002 to $34.1 million in 2003, an increase of $13.7 million (67.2%). The increase in revenue associated with the delivery of energy under basis transactions was equal to the entire net variance in this category of revenues, $13.7 million. However, there were variances in other elements of this category that tended to offset one another. Revenue from the sale of wheeling service to other utilities increased by $2.0 million from 2002 to 2003. The sale of reserves to other purchasers of the Bonneville Slice product, an activity that was initiated in October 2003, added $1.4 million to revenues. Other power-related transactions added an additional $1.4 million. Offsetting these increases was a reduction of $2.0 million in the valuation of energy delivered by the Department under exchange agreements, which largely reflected the termination of an exchange agreement with Idaho Power; a decrease of $1.1 million in rental payments from Bonneville for the use of transmission facilities; and a decrease of $1.0 million in revenue from integration and exchange services provided by the Department in connection with wind generation.

***Other (Miscellaneous) Revenues*–**Other revenues increased from $13.0 million in 2002 to $15.0 million in 2003, an increase of $2.0 million (15.8%). Late fees and interest charges on delinquent accounts increased by $1.5 million, from $3.9 million in 2002 to $5.4 million in 2003. Revenue from the rental of transmission towers to telecommunications companies for antenna attachments generated an increase of $0.5 million in revenue. Settlement of a claim related to the performance of turbine runners installed at the Boundary Project provided $1.2 million in additional revenue. Revenue from these sources was offset by net decreases in property rentals, damage recoveries, and other sources totaling $1.2 million.

OPERATING EXPENSES

Operating expenses in 2003 totaled $700.1 million, an increase of $60.9 million (9.5%) from the prior year. Power and transmission costs account for $43.2 million of this increase. Other operations and maintenance costs showed an increase of $13.5 million. Smaller increases were recorded in depreciation and taxes.

***Long-Term Purchased Power*–**The cost of energy purchased from other utilities through long-term contracts increased from $222.9 million in 2002 to $240.5 million in 2003, an increase of $17.6 million (7.9%).

***Bonneville Power Administration ("Bonneville")*–**The cost of power purchased from Bonneville increased by $22.3 million, from $134.8 million in 2002 to $157.1 million in 2003. The Department's contract with Bonneville provides for purchases of energy in two forms. First, the Department purchases a fixed block of energy in amounts shaped to its net monthly power requirements at rates set through Bonneville's rate-setting processes. Second, the Department purchases a product commonly known as the "Slice of the System", which entitles the Department to receive 4.6676% of the output of the Federal Columbia River Power System and which requires the Department to pay the same percentage of the costs of the system. The contract also provides for after-the-fact true-up payments to reconcile actual costs with the projected costs on which billings are based. The true-up payment of $10.4 million was deferred at the end of 2002 to be amortized over the period from April 1, 2003, through February 29, 2004, and in 2003, the Department recorded an amortization expense of $8.6 million. A true-up credit for 2003 of $6.3 million was deferred at the end of 2003, and will be recognized during 2004. In 2002, the Department elected to reduce its Slice entitlement in return for a reduction of $14.7 million in its Slice bills. No such reduction occurred in 2003. Other true-up adjustments added $2.3 million to the cost of Bonneville power in 2003. The cost of energy purchased as a block was $1.8 million higher in 2003 than in the preceding year. These increases were offset by reductions in the rates charged for the Slice product in 2003, which lowered costs by $5.1 million relative to 2002. The amount of energy received from Bonneville in 2003 was 4,713,124 MWh, slightly higher than the 4,659,586 MWh received in 2002.

Wind Generation–The cost of power purchased from the State Line Wind Project, located in Walla Walla County, Washington, and Umatilla County, Oregon, increased from $6.5 million in 2002 to $11.3 million in 2003. Costs include the cost of integration and exchange services required to deliver energy from the project as a constant amount across all hours. The increase in costs reflects a doubling of the energy received from wind generation, from 106,493 MWh in 2002 to 216,290 MWh in 2003.

Klamath Falls–Expenses related to the Department's contract for power from the Klamath Falls Cogeneration Project fell from $39.7 million in 2002 to $36.3 million in 2003, a reduction of $3.4 million (8.6%). Total fuel costs were $21.8 million in 2003 compared to $25.2 million in 2002, reflecting decreases in the average cost of fuel during 2003. Energy delivered from Klamath Falls to the Department in 2003 totaled 654,502 MWh, a reduction of 55,018 MWh (7.8%) from the 2002 level. The Department elected to take power from the plant in only nine months in 2003, compared to 10 months in 2002.

Grand Coulee Project Hydroelectric Authority–The Department contracts for 50% of the output of a series of small hydroelectric projects operated by irrigation districts in the Columbia Basin in Central Washington. In 2003, the Department's share of the cost of power from these projects was $4.8 million, a decrease of $2.5 million (34.0%) from the 2002 level. Debt service costs fell by $0.5 million. An increase of $1.3 million in incentive payments to the irrigation districts in 2003 was offset by the fact that a true-up payment of $3.4 million in 2002 related to past incentive payments was not repeated in 2003.

Seasonal Exchanges–Expenses associated with the receipt of power under seasonal exchange agreements were $3.1 million lower in 2003 than in 2002. An exchange agreement with Idaho Power terminated on October 31, 2002, and was not renewed; power valued at $1.4 million was delivered to the Department in 2002 under this agreement. The blended weighted average cost of power, which is used to value power delivered and received under the exchange agreements, increased from 2002 to 2003 in the months in which power is received under an exchange agreement with Tacoma Power, resulting in an increase in the cost of long-term purchased power of $0.4 million. In the months in which energy is received under an agreement with the Northern California Power Authority the blended weighted average cost of power declined, resulting in a reduction of $2.1 million in expenses from 2002 to 2003. (The net reduction of $3.1 million in seasonal exchange expenses is offset by the $2.0 million reduction in seasonal exchange revenues discussed above, providing an increase in net revenues of $1.1 million from the valuation of seasonal power exchanges.)

Other Power Contracts–The cost of power delivered to the Department under contracts with Pend Oreille County PUD No. 1 and Grant County PUD No. 1 increased by $0.2 million and $0.3 million, respectively. Payment to King County Metro for power from Metro's cogeneration facility at the West Point Sewage Treatment Project were $0.2 million lower than in 2002.

Amortization of Deferred Power Costs–In both 2002 and 2003, $100 million in power costs deferred from 2001 were amortized. The remaining $100 million of deferred power costs from 2001 will be amortized in 2004.

Short-Term Wholesale Power Purchases–The cost of short-term purchases of energy in the wholesale market increased from $12.4 million in 2002 to $24.2 million in 2003, an increase of $11.8 million (94.8%). The increase reflects both an increase in the amounts purchased (from 898,613 MWh in 2002 to 1,210,699 MWh in 2003) and an increase in the average price of the purchases (from $25.77 per MWh in 2002 to $37.61 per MWh in 2003).

Other Wholesale Power Transactions–Expenses related to other power-related transactions increased from $1.9 million in 2002 to $13.9 million in 2003, an increase of $12.0 million. Virtually all of this increase is attributable to the purchase component of basis transactions with counterparties, which increased from $1.3 million to $13.4 million. When both the sale and purchase components of these transactions are taken into account, net revenue of $2.5 million was recognized in 2003, compared to $0.9 million in 2002.

Other Power Costs–The cost of operating the Department's System Control Center and other power-related costs increased from $6.3 million in 2002 to $7.3 million in 2003. Data processing costs at the Control Center account for most of the increase.

Generation–Costs associated with the operation and maintenance of the Department's hydroelectric generating plants increased from $18.5 million in 2002 to $20.2 million in 2003, an increase of $1.7 million (9.0%). Increases in the payments to the Federal Energy Regulatory Commission ("FERC") for fees, and to other regional utilities for upstream benefits, contributed to the increase in generation expenses.

Transmission–Transmission costs, including the cost of wheeling power over the facilities of BPA and other utilities, totaled $34.5 million in 2003, a reduction of $0.9 million (2.4%) from the level of $35.4 million recorded in 2002. The cost of operating and maintaining transmission facilities owned by the Department increased from $4.3 million to $4.4 million. Wheeling costs fell from $31.1 million in 2002 to $30.1 million in 2003, largely as a result of a reduction in the amount paid to Idaho Power Company for transmission of power from the Lucky Peak project. Prior to October 1, 2002, the Department contracted with Idaho Power to transmit Lucky Peak power to the point of delivery under an exchange agreement with Idaho Power. When the exchange agreement terminated on October 1, 2002, the Department contracted to sell Lucky Peak energy to another counterparty with delivery at the generating plant, thus obviating the need to transmit the power over Idaho Power's lines.

Distribution–Distribution expenses increased from $37.6 million in 2002 to $39.1 million in 2003, an increase of $1.5 million (3.9%). Decreases in the cost of tree-trimming ($1.7 million) and apprenticeship programs ($0.5 million) were partially offset by increases in maintenance of the overhead system ($1.0 million) for storm damage repair and other corrective maintenance, safety program ($0.2 million) and maintenance of underground systems ($0.2 million). In addition, planning costs totaling $1.5 million related to transportation infrastructure projects and the redevelopment of the South Lake Union area were expensed in 2003; there were no corresponding expenses in 2002.

Customer Services–The cost of customer services increased from $27.6 million in 2002 to $31.1 million in 2003, an increase of $3.5 million (12.7%). The increase is primarily attributable to growth in bad debt expenses, which increased from $5.2 million in 2002 to $8.9 million in 2003, an increase of $3.7 million. Bad debt expenses for retail electric accounts increased from $5.0 million in 2002 to $7.4 million in 2003, reflecting the downturn in the local economy and the substantial rate increases implemented by the Department in 2001. The bankruptcy of two counterparties to which the Department had delivered wholesale power in 2003 left the Department with $1.0 million in receivables with uncertain prospects of recovery and that amount was expensed. Bad debt expenses in nonelectric accounts also increased by $0.2 million from 2002 to 2003.

Conservation–Conservation expenses increased from $9.5 million in 2002 to $11.0 million in 2003, an increase of $1.5 million (15.8%). Programmatic conservation expenditures are deferred and amortized over the anticipated 20-year life of the conservation improvements. Most of the increase in expense from 2002 to 2003 is attributable to the amortization of past conservation investments, which increased from $7.4 million in 2002 to $8.3 million in 2003. Conservation costs that are expensed on a current basis increased from $2.1 million in 2002 to $2.7 million in 2003.

Administration and General–Administration and general expenses increased by $7.1 million (17.6%), from $40.3 million in 2002 to $47.4 million in 2003. The amount expensed to recognize the Department's liability for cleanup of a Superfund site on the Duwamish Waterway increased by $3.4 million. Judgments and claims were $0.9 million higher than in 2002. Legal fees, including the cost of pursuing the Department's claims for a refund of power costs incurred during the power crisis of 2001, increased by $1.5 million. New oversight functions created in 2003, including the Department's Advisory Board, added $0.7 million to expenses. Information technology costs increased by $1.3 million over the 2002 level for the network, desktop support services, and automated systems including asset management and human resources. Other general administrative and engineering expenses increased by a net $2.2 million. Administration and general costs applied to capital improvement projects and other deferred projects were $0.3 million lower in 2003. Offsetting these increases was a $3.2 million reduction in industrial insurance costs.

Depreciation–Depreciation expense rose from $66.5 million in 2002 to $69.3 million in 2003, an increase of $2.8 million (4.2%), reflecting increases in net plant as the Department implemented its capital improvement program. The increases were concentrated in distribution and general plant (including data processing hardware and software), each of which showed an increase of $1.1 million.

Taxes–Tax expenses increased by $1.4 million (2.4%), from $60.2 million in 2002 to $61.6 million in 2003. Revenue-based taxes payable to the City of Seattle and the state of Washington were $0.7 million lower than in 2002, due to the reduction in retail revenue. However, payments to suburban jurisdictions increased from $2.1 million in 2002 to $2.8 million in 2003, due largely to the initiation of payments to the City of Tukwila under their new franchise agreement with Seattle. Assessments related to tax audits added $1.1 million to expenses in 2003.

NONOPERATING REVENUE (EXPENSE)

Investment Income–Income from the investment of the Department's available cash balances fell from $10.1 million in 2002 to $3.8 million in 2003. Interest earnings on the construction account decreased by $3.3 million, from $4.5 million to $1.2 million as proceeds from the sale of bonds in 2001 were expended and as interest rates fell. Lower interest rates account for a decrease of $0.8 million in interest earnings on the investment of balances in the bond reserve account. Adjusting the value of the Department's investments at year end to reflect fair market value resulted in a charge of $2.5 million. Offsetting these decreases was an increase of $0.4 million in interest earned on the investment of operating cash balances in the City's cash pool.

Debt Expense–Interest expense, plus the amortization of debt-related costs, was $7.0 million lower in 2003 than in 2002, declining from $84.1 million to $77.1 million. Interest costs related to revenue anticipation notes issued in 2001 and 2002 to finance power costs during the 2001 power crisis fell from $8.9 million in 2002 to $4.8 million in 2003 as the notes were retired in March and November 2003. Interest on the Department's loans from the City's cash pool declined from $2.6 million to $0.5 million as both the amount of borrowing and interest rates decreased. The refunding of $86.6 million of first lien bonds in December 2002 and the retirement of outstanding bonds at their scheduled maturity resulted in a reduction of interest on first-lien bonds from $71.9 million to $71.3 million. Low short-term interest rates resulted in a reduction of $0.4 million in interest expense on second-lien bonds, most of which have interest rates reset on a weekly basis. The allowance for funds used during construction, which is a credit against interest expense, was $0.7 million higher in 2003 than in 2002, lowering interest expense by the same amount. Other expenses, including the amortization of debt-related costs, rose by $0.8 million from the 2002 level.

Contributions and Grants–Contributions in aid of construction and grants more than doubled from $13.0 million in 2002 to $26.1 million in 2003. The Bonneville Power Administration reimbursed the Department for $3.6 million of costs incurred by the Department for the North Seattle transmission reinforcement project. Other contributions increased by $2.0 million. Donations of facilities constructed in connection with arterial improvement projects showed an increase of $7.7 million. Grants related to local and regional transit projects added $1.7 million to this category. Offsetting these increases was a reduction of $1.8 million in contributions associated with nonstandard service installations.

FINANCIAL POSITION

Significant capital assets and related long-term debt

As of December 31,	2003	2002
SIGNIFICANT CAPITAL ASSETS:		
Utility plant—at original cost:		
Hydraulic	$ 558,719,929	$ 527,022,003
Capacity rights—3rd AC Intertie	34,298,665	34,298,666
Transmission	111,682,093	105,652,942
Distribution	1,139,408,622	1,068,429,863
General plant	308,571,436	297,080,941
	2,152,680,745	2,032,484,415
Less accumulated depreciation	(914,978,513)	(862,964,940)
	1,237,702,232	1,169,519,475
Construction work-in-progress	101,523,497	135,358,152
Nonoperating property—net of accumulated depreciation	11,860,650	7,703,571
Land and land rights	39,770,983	32,854,384
	$1,390,857,362	$1,345,435,582
SIGNIFICANT LONG-TERM DEBT RELATED TO CAPITAL ASSETS:		
Revenue bonds	$1,235,574,847	$1,176,151,459
Bond premium—net	22,932,295	12,652,403
Less deferred charges on advanced refunding	(31,260,375)	(33,124,397)
Note payable—City of Seattle	5,158,625	
	$1,232,405,392	$1,155,679,465
INVESTED IN CAPITAL ASSETS—NET OF RELATED DEBT:	$ 158,451,970	$ 189,756,117

CONDENSED BALANCE SHEETS

As of December 31,	2003	2002
Assets:		
Utility plant	$ 1,390,857,362	$1,345,435,582
Capitalized purchased power commitment	45,130,152	50,279,621
Restricted assets	159,432,145	240,881,958
Current assets	178,234,062	190,990,153
Other assets	286,898,970	377,433,352
Total assets	$ 2,060,552,691	$2,205,020,666
Liabilities:		
Long-term debt	$ 1,462,609,162	$1,365,447,879
Noncurrent liabilities	55,717,497	67,994,521
Current liabilities	215,129,588	452,101,465
Deferred credits	36,970,209	21,216,712
Total liabilities	1,770,426,456	1,906,760,577
Equity:		
Invested in capital assets—net of related debt	158,451,970	189,756,117
Restricted:		
Deferred power costs	100,000,000	200,000,000
Other	56,831,686	68,755,147
Unrestricted	(25,157,421)	(160,251,175)
	290,126,235	298,260,089
Total liabilities and equity	$ 2,060,552,691	$2,205,020,666

UTILITY PLANT

Utility plant at original cost increased $120.2 million.

The hydroelectric system increased $31.7 million, of which 77.3% was for Boundary dam and included accessory electrical equipment, structures and improvements, waterwheels and turbines, generators, and waterways.

Transmission plant increased $6.0 million with station equipment at Bothell increasing $4.2 million.

The distribution system increased $71 million, primarily for conductors, conduits, and other devices ($44.8 million). Poles and towers improvements increased $7.5 million. Service improvements (to connect the Department's system to the customer's system) increased $6.3 million and transformers increased $6.1 million. Street lighting increased $2.8 million, mostly within the Seattle city limits. Meters increased $2.0 million.

General plant increased $11.5 million, primarily due to a $8.6 million increase for automated systems and $3.7 million for communication equipment.

In addition to utility plant at original cost, land and land rights increased $6.9 million, due primarily to acquisition of a property on Roy Street from the Seattle Parks Department for $5.6 million.

COST CAPITALIZATION POLICIES

Administration and General ("A&G") Costs–The Department allocates a portion of A&G costs to the Capital Improvement and Conservation Program ("CICP"). A pool of allocable A&G costs is identified and an A&G allocation rate is computed by dividing the projected level of costs in the A&G cost pool in the following year by the projected number of non-A&G direct labor hours. Actual CICP labor hours are multiplied by the A&G allocation rate and included as a component of a CICP project. A&G costs capitalized were $19.1 million and $19.4 million in 2003 and 2002, respectively.

In addition, the Department allocates costs for pension and benefits to both CICP projects and operations and maintenance expenses. Pensions and benefits overhead applied totaled $21.8 million and $20.3 million in 2003 and 2002, respectively.

Data Processing Systems–Systems development costs related to major new data processing applications are capitalized.

High Ross–In setting rates for the 2000 to 2003 period, the City of Seattle Council decided to defer the capital portion of the remaining payments to B. C. Hydro under the High Ross agreement over the period through 2035. The deferred portion of the High Ross payments is treated as a component of capital requirements.

Capitalization Limit–The Department of Executive Administration revised the capitalization limit for the City of Seattle from $1,000 to $5,000 beginning in 2002. The effect of this change is an increase of approximately $2.0 million of charges, which were expensed in 2002 rather than capitalized.

OTHER ASSETS

Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation,* provides for the deferral of certain utility costs and related recognition in future years as the costs are recovered through future rates. Deferred costs are authorized by resolutions passed by the Seattle City Council, and include capitalized energy management services-net, deferred power costs, capitalized relicensing costs, and other deferred charges and assets. Detail for other deferred charges and assets-net, is provided in Note 10 to the accompanying financial statements.

Deferred assets totaled $286.9 million at December 31, 2003, decreasing $90.5 million from December 31, 2002. In 2001, $300 million of short-term wholesale power costs were deferred for recovery through future revenues. In 2003 and in 2002, $100 million of the deferred power costs were amortized each year. The balance of $100 million is expected to be recovered by the end of 2004.

The Department is subject to true-up payments for the Department's fixed 4.6676 percentage of actual output and costs of Bonneville Slice power through October 1, 2011. In 2002, $10.4 million was deferred for the Bonneville Slice contract true-up billing and $1.9 million remained unamortized at December 31, 2003. A true-up credit for federal fiscal year 2003 in the amount of $6.3 million was deferred as of December 31, 2003, and will be recognized during 2004. Bonneville rate adjustments will be passed through to retail electric customers in the form of rate adjustments in accordance with the rates ordinance.

LONG-TERM DEBT

Activity during the year for long-term debt included issuance of $251.85 million in Municipal Light & Power Improvement and Refunding Revenue Bonds, 2003. The proceeds were used to fund the ongoing Capital Improvement Program and to defease certain prior lien bonds. Scheduled redemption of certain prior lien bonds also took place in the normal course of business. A note payable to the City of Seattle for $5.6 million for purchase of real estate was also issued (see Note 6 of the accompanying financial statements).

After payment of cash operating expenses, net revenues available to pay debt service were equal to 2.5 times principal and interest on first-lien bonds. If, in addition, the amortization of $100 million in power costs deferred from 2001 is taken into account, net revenues would be equal to 1.56 times first-lien debt service.

ENVIRONMENTAL LIABILITIES

Environmental liabilities totaled $5.8 million and $2.6 million at December 31, 2003 and 2002, respectively. The increase in the liability from 2002 is primarily attributable to the estimated cost of remediating contaminated sediments in the lower Duwamish Waterway, which was designated a federal Superfund site by the Environmental Protection Agency in 2001. The Department is considered a potentially responsible party for contamination in the Duwamish River due to land ownership or use of property located along the river.

RISK MANAGEMENT

The Department's exposure to market risk is actively managed by a Risk Management Committee. The Department is fundamentally risk averse, engaging in market transactions only to meet its load obligations or to lay off surplus energy. Except for strictly limited and closely monitored intraday and interday trading to take advantage of owned hydro storage, the Department does not take market positions in anticipation of generating revenue.

With a significant portion of the Department's revenue expected from wholesale market sales, great emphasis is placed on the management of market risk. Processes, policies, and procedures designed to monitor and control these market risks, including credit risk, are in place and engagement in the market is strictly governed by those policies. Formal segregation of the roles of the front, middle, and back offices ensures compliance.

The Department measures the market price risk in its portfolio on a weekly basis using a modified revenue at risk measure that reflects not only price risk, but also the volumetric risk associated with its hydro-dominated power portfolio. Monte Carlo simulation is used to capture financial risk and scenario analysis for stress testing.

The Department takes a very conservative approach to managing volumetric risk, assuming 95% exceedance in hydro-generation until observed precipitation or snow pack surveys indicate otherwise.

While the Department's portfolio includes a gas turbine (a share of the Klamath plant), the Department's exposure to gas price excursions is limited, as the Department has monthly dispatch rights for that resource and only exercises those rights if the economics of operating the plant is favorable.

The Department mitigates credit risk by trading only with qualified counterparties. The Credit Committee, a subcommittee of the Risk Management Committee, establishes credit policies and counterparty limits based on approved criteria. The Committee monitors credit exposure and updates counterparty limits to reflect their most current financial condition and creditworthiness.

BALANCE SHEETS

As of December 31,	2003	2002
ASSETS		
UTILITY PLANT—At original cost:		
Plant in service—excluding land	$2,152,680,745	$ 2,032,484,415
Less accumulated depreciation	(914,978,513)	(862,964,940)
	1,237,702,232	1,169,519,475
Construction work-in-progress	101,523,497	135,358,152
Nonoperating property—net of accumulated depreciation	11,860,650	7,703,571
Land and land rights	39,770,983	32,854,384
	1,390,857,362	1,345,435,582
CAPITALIZED PURCHASED POWER COMMITMENT	45,130,152	50,279,621
RESTRICTED ASSETS:		
Municipal Light & Power Bond Reserve Account:		
Cash and equity in pooled investments	79,622,670	77,975,000
Bond proceeds and other:		
Cash and equity in pooled investments	7,406,387	158,267,512
Investments	68,244,446	
Special deposits and other	4,158,642	4,639,446
	159,432,145	240,881,958
CURRENT ASSETS:		
Cash and equity in pooled investments	9,347,170	34,694,513
Accounts receivable, net of allowance of $12,630,000 and $6,690,000	82,589,514	73,345,049
Unbilled revenues	61,194,790	60,079,107
Energy contracts	5,496,378	1,848,350
Materials and supplies at average cost	18,724,736	20,447,710
Prepayments, interest receivable, and other	881,474	575,424
	178,234,062	190,990,153
OTHER ASSETS:		
Capitalized energy management services—net	116,277,404	108,005,350
Deferred power costs	100,000,000	200,000,000
Capitalized relicensing costs	14,328,345	12,764,867
Other deferred charges and assets—net	56,293,221	56,663,135
	286,898,970	377,433,352
TOTAL	$2,060,552,691	$ 2,205,020,666

See notes to financial statements.

As of December 31,	2003	2002
LIABILITIES		
LONG-TERM DEBT:		
Revenue bonds	$ 1,521,526,000	$ 1,429,186,000
Plus bond premium—net	28,239,553	17,127,583
Less deferred charges on advanced refunding	(38,495,016)	(40,250,704)
Less revenue bonds—current portion	(53,820,000)	(40,615,000)
Note payable—City of Seattle	5,158,625	
	1,462,609,162	1,365,447,879
NONCURRENT LIABILITIES:		
Accumulated provision for injuries and damages	10,491,426	7,895,490
Compensated absences	10,221,563	9,819,410
Long-term purchased power obligation	45,130,152	50,279,621
Less obligation—current portion	(10,300,000)	
Other	174,356	
	55,717,497	67,994,521
CURRENT LIABILITIES:		
Accounts payable and other	52,222,132	71,842,294
Accrued payroll and related taxes	4,949,166	4,668,171
Compensated absences	495,974	846,948
Accrued interest	19,797,650	21,531,101
Revenue anticipation notes		307,210,000
Short-term borrowings—City of Seattle	70,000,000	
Long-term debt	53,820,000	40,615,000
Purchased power obligation	10,300,000	
Energy contracts	3,544,666	5,387,951
	215,129,588	452,101,465
DEFERRED CREDITS	36,970,209	21,216,712
Total liabilities	1,770,426,456	1,906,760,577
COMMITMENTS AND CONTINGENCIES (Note 13)		
EQUITY:		
Invested in capital assets—net of related debt	158,451,970	189,756,117
Restricted:		
Deferred power costs	100,000,000	200,000,000
Other	56,831,686	68,755,147
Unrestricted	(25,157,421)	(160,251,175)
	290,126,235	298,260,089
TOTAL	$ 2,060,552,691	$ 2,205,020,666

STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN EQUITY

Years Ended December 31,	2003	2002
OPERATING REVENUES:		
Retail power revenues	$ 552,232,914	$ 562,432,218
Short-term wholesale power revenues	137,650,966	102,082,572
Other power-related revenues	34,082,244	20,385,528
Other	15,039,174	12,991,925
	739,005,298	697,892,243
OPERATING EXPENSES:		
Long-term purchased power	240,505,211	222,943,642
Short-term wholesale power purchases	24,232,720	12,440,806
Amortization of deferred power costs	100,000,000	100,000,000
Other power expenses	21,139,577	8,147,996
Generation	20,210,903	18,546,296
Transmission	34,511,283	35,352,620
Distribution	39,116,032	37,649,578
Customer service	31,068,350	27,566,006
Energy management	11,014,634	9,514,572
Administrative and general	88,316,671	79,973,873
Administrative and general overhead applied	(40,924,230)	(39,658,495)
City of Seattle occupation tax	33,607,729	33,913,510
Other taxes	27,998,595	26,260,379
Depreciation	69,270,029	66,485,780
	700,067,504	639,136,563
Net operating income	38,937,794	58,755,680
NONOPERATING REVENUES (EXPENSES):		
Investment income	3,813,194	10,110,004
Interest expense	(73,934,677)	(81,340,397)
Amortization of debt expense	(3,120,011)	(2,717,316)
Other income–net	36,192	357,968
	(73,205,302)	(73,589,741)
Net loss before fees and grants	(34,267,508)	(14,834,061)
FEES AND GRANTS:		
Capital contributions	22,089,096	10,631,017
Grants	4,044,558	2,337,759
	26,133,654	12,968,776
NET LOSS	(8,133,854)	(1,865,285)
EQUITY:		
Beginning of year	298,260,089	300,125,374
End of year	$ 290,126,235	$ 298,260,089

See notes to financial statements.

STATEMENTS OF CASH FLOWS

Years Ended December 31,	2003	2002
OPERATING ACTIVITIES:		
Cash received from customers and counterparties	$ 751,992,693	$ 672,615,777
Cash paid to suppliers, employees, and counterparties	(468,444,688)	(375,770,304)
Taxes paid	(68,610,633)	(59,423,235)
Net cash provided by operating activities	214,937,372	237,422,238
NONCAPITAL FINANCING ACTIVITIES:		
(Repayment of) proceeds from Revenue Anticipation Note ("RAN")	(307,210,000)	125,922,862
Increase (decrease) in short-term borrowings—City of Seattle note	70,000,000	(100,000,000)
Interest paid on RAN	(7,324,362)	(8,541,075)
Interest paid on City of Seattle note	(216,284)	(2,910,225)
Grants received	2,235,516	1,289,390
Bonneville receipts for conservation augmentation	10,716,542	19,996,026
Payment to vendors on behalf of customers for conservation augmentation	(17,910,624)	(18,240,747)
Net cash (used in) provided by noncapital financing activities	(249,709,212)	17,516,231
CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from long-term borrowing—net of discount	265,520,394	88,247,757
Payment to trustee for refunded bonds	(123,962,517)	(86,560,000)
Bond issue costs paid	(1,606,283)	(585,657)
Principal paid on long-term debt	(40,615,000)	(41,651,500)
Interest paid on long-term debt	(69,694,188)	(74,984,816)
Acquisition and construction of capital assets	(118,390,142)	(133,586,924)
Proceeds from sale of property, plant, and equipment	709,000	763,624
Contributions in aid of construction	10,811,821	11,578,573
Net cash (used in) capital and related financing activities	(77,226,915)	(236,778,943)
INVESTING ACTIVITIES:		
Proceeds from investments	40,650,838	216,780,918
Purchases of investments	(108,896,905)	(114,511,442)
Interest received on investments	5,203,219	10,230,016
Net cash (used in) provided by investing activities	(63,042,848)	112,499,492
NET (DECREASE) INCREASE IN CASH AND EQUITY IN POOLED INVESTMENTS	(175,041,603)	130,659,018
CASH AND EQUITY IN POOLED INVESTMENTS:		
Beginning of year	275,576,471	144,917,453
End of year	$ 100,534,868	$ 275,576,471

(continued)

STATEMENTS OF CASH FLOWS

Years Ended December 31,	2003	2002
RECONCILIATION OF NET OPERATING INCOME		
TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Net operating income	$ 38,937,794	$ 58,755,680
Adjustments to reconcile operating income		
to net cash provided by operating activities:		
Depreciation and amortization	79,981,627	76,288,439
Amortization of deferred power costs	100,000,000	100,000,000
Change in:		
Accounts receivable	(3,974,205)	(15,586,755)
Unbilled revenues	(1,115,683)	1,287,056
Materials and supplies	1,722,974	3,895,411
Prepayments, interest receivable, and other	(3,954,078)	(571,654)
Capitalized relicensing and other deferred	7,679,878	12,210,283
Provision for injuries and damages and claims payable	3,181,299	1,770,185
Accounts payable, accrued payroll, and other	(19,924,530)	6,800,764
Compensated absences	51,179	13,006
Energy contracts and deferred credits	12,351,117	(7,440,177)
Total adjustments	175,999,578	178,666,558
Net cash provided by operating activities	$ 214,937,372	$ 237,422,238
SUPPLEMENTAL DISCLOSURES OF NONCASH ACTIVITIES:		
In-kind capital contributions	$ 9,220,363	$ 1,566,788
Note payable incurred for purchase of property	$ 5,565,000	$ –

See notes to financial statements.

(Concluded)

1. OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The City Light Department (the "Department") is the public electric utility of the City of Seattle (the "City"). The Department owns and operates certain generating, transmission, and distribution facilities and supplies electricity to approximately 365,445 customers. The Department supplies electrical energy to other City agencies at rates prescribed by City ordinances. The establishment of the Department's rates is within the exclusive jurisdiction of the Seattle City Council. A requirement of Washington State law provides that rates must be fair, nondiscriminatory, and fixed to produce revenue adequate to pay for operation and maintenance expenses and to meet all debt service requirements payable from such revenue. The Department pays occupation taxes to the City based on total revenues.

The Department's revenues were $6.4 million and $6.0 million for electrical energy and $1.9 million and $2.3 million for nonenergy services provided to other city funds in 2003 and 2002, respectively.

The Department receives certain services from other City funds and paid approximately $35.7 million and $36.9 million, respectively, in 2003 and 2002 for such services.

Accounting Standards–The accounting and reporting policies of the Department are regulated by the Washington State Auditor's Office, Division of Municipal Corporations, and are based on the Uniform System of Accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission ("FERC"). The financial statements are also prepared in conformity with accounting principles generally accepted in the United States of America as applied to governmental units. The Governmental Accounting Standards Board ("GASB") is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The Department has applied all applicable GASB pronouncements as well as the following pronouncements, except for those that conflict with or contradict GASB pronouncements: Statements and Interpretations of the Financial Accounting Standards Board ("FASB"), Accounting Principles Board Opinions, and Accounting Research Bulletins of the Committee on Accounting Procedures. The more significant of the Department's accounting policies are described below.

In June 1999, the GASB issued GASB Statement No. 34, *Basic Financial Statements-and Management's Discussion and Analysis-for State and Local Governments,* adopted by the Department in 2002 with the following amendments: GASB Statement No. 37, *Basic Financial Statements-and Management's Discussion and Analysis-for State and Local Governments: Omnibus-an Amendment of GASB Statements No. 21 and No. 34,* and GASB Statement No. 38, *Certain Financial Statement Note Disclosures.* GASB Statement No. 34, as amended, and GASB Statement No. 38 establish specific standards for external financial reporting for state and local governments. As a result of adopting these statements in 2002, the basic financial statement presentation was significantly changed, including adding management's discussion and analysis of operating, investing, and financing activities.

GASB Statement No. 34 also requires the classification of fund equity into three components: invested in capital assets-net of related debt, restricted, and unrestricted, defined as follows:

- *Invested in capital assets-net of related debt* consists of capital assets, net of accumulated depreciation reduced by the net outstanding debt balances.
- *Restricted net assets* has constraints placed on use, either externally or internally. Constraints include those imposed by creditors (such as through debt covenants), grants, or laws and regulations of other governments, or by law through constitutional provisions or enabling legislation or by the Seattle City Council.
- *Unrestricted net assets (deficit)* consists of assets and liabilities that do not meet the definition of "restricted net assets" or "invested in capital assets-net of related debt."

Under GASB Statement No. 34, the statement of operations and changes in retained earnings was renamed the statement of revenues, expenses, and changes in equity.

In June 2001, the FASB issued Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations,* which addresses financial accounting and reporting for legal or contractual obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. This statement requires the recording of the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation will be capitalized as part of the carrying amount of the related long-lived asset. The liability will be accreted to its present value each period and the related capitalized costs will be depreciated over the useful life of the related asset. Upon retirement of the asset, the Department will either settle the retirement obligation for its recorded amount or incur a gain or loss. The adoption of this statement on January 1, 2003, did not have a material effect on the Department's financial position or operations.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities*. The Department has entered into certain forward contracts to purchase or sell power that may no longer meet the normal purchases and sales exception in accordance with the provisions of SFAS No. 149. This statement requires these types of forward contracts to purchase or sell power, which were entered into on or after July 1, 2003, be recorded as assets or liabilities at market value with an offsetting regulatory asset or liability as allowed under SFAS No. 71, *Accounting for the Effects of Certain Types of Regulation*.

In July 2003, the Emerging Issues Task Force ("EITF") reached consensus on Issue No. 03-11, *Reporting Realized Gains and Losses on Derivative Instruments That Are Subject to FASB Statement No. 133 and Not "Held for Trading Purposes"* as Defined in EITF Issue No. 02-3. This EITF issue requires that revenues and expenses from the Department's settled energy contracts that are "booked out" (not physically delivered) should be reported on a net basis as part of operating revenues. As allowed by this EITF issue, the Department applied these provisions for the entire year in 2003 and reclassified 2002 to conform to current-year presentation. Booked-out power transactions reduced revenues and expenses by $21.3 million and $10.7 million in 2003 and 2002, respectively.

In March 2003, the GASB issued Statement No. 40, *Deposit and Investment Risk Disclosures*. This statement establishes and modifies disclosure requirements related to investment risks: credit risk (including custodial credit risk and concentrations of credit risk), interest rate risk, and foreign currency risk. This statement also establishes and modifies disclosure requirements for deposit risks: custodial credit risk and foreign currency risk. The requirements of this statement are effective for the Department's financial statements for periods beginning after June 15, 2004 (January 1, 2005). The Department is in the process of determining the impact of this standard on its financial statements.

GASB Statement No. 42, *Accounting and Financial Reporting for Impairment of Capital Assets and for Insurance Recoveries,* establishes accounting and financial reporting standards for impairment of capital assets. A capital asset is considered impaired when its service utility has declined significantly and unexpectedly. This statement also clarifies and establishes accounting requirements for insurance recoveries. The Department will adopt this statement effective January 1, 2005; however, the Department does not expect a material impact on its financial position or results of operations.

In June 2003, the GASB issued Technical Bulletin No. 2003-1 ("TB 03-1"), *Disclosure Requirements for Derivatives Not Reported at Fair Value on the Statement of Net Assets,* which supersedes Technical Bulletin 94-1 and clarifies guidance on derivative disclosures, pending the results of the GASB's project on reporting and measurement of derivatives and hedging activities. TB 03-1 is effective for fiscal years ending after June 15, 2003, and was adopted by the Department in 2003 without material impact to financial position or operations.

Utility Plant–Utility plant is recorded at original cost, which includes both direct costs of construction or acquisition and indirect costs, including an allowance for funds used during construction. The allowance represents the estimated costs of financing construction projects and is computed using the Department's long-term borrowing rate. The allowance totaled $4.3 million and $3.6 million in 2003 and 2002, respectively, and is reflected as a reduction of interest expense in the statements of revenues, expenses, and changes in equity. Property constructed with capital fees received from customers is included in utility plant. Capital fees totaled $22.1 million in 2003 and $10.6 million in 2002. Provision for depreciation is made using the straight-line method based upon estimated economic lives, which range from three to 50 years, of related operating assets. The Department uses a half-year convention method on the assumption that additions and replacements are placed in service at mid-year. The composite depreciation rate was approximately 3.2% in 2003 and 3.3% in 2002. When operating plant assets are retired, their original cost together with removal costs, less salvage, is charged to accumulated depreciation. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and betterments is capitalized. The Department periodically reviews long-lived assets for impairment to determine whether any events or circumstances indicate the carrying value of the assets may not be recoverable. No impairment was identified in 2002 or 2003.

Restricted Assets–In accordance with the Department's bond resolutions, state law, or other agreements, separate restricted assets have been established. These assets are restricted for specific purposes, including the establishment of the Municipal Light & Power ("ML&P") Bond Reserve Account, financing of the Department's ongoing Capital Improvement Program, and other purposes.

Compensated Absences–Permanent employees of the Department earn vacation time in accordance with length of service. A maximum of 480 hours may be accumulated and, upon termination, employees are entitled to compensation for unused vacation. At retirement, employees receive compensation equivalent to 25% of their accumulated sick leave. The Department accrues all costs associated with compensated absences, including payroll taxes.

Accounts Payable and Other–The composition of accounts payable and other at December 31 is as follows:

	2003	2002
Vouchers payable	$ 7,471,873	$10,090,145
Power accounts payable	24,540,593	40,354,341
Interfund payable	5,892,236	6,566,460
Taxes payable	9,528,936	8,541,055
Claims payable—current	3,166,115	2,580,752
Guarantee deposit and contract retainer	1,502,526	1,998,070
Other accounts payable	119,853	1,711,471
	$52,222,132	$71,842,294

Revenue Recognition–Service rates are authorized by City ordinances. Billings are made to customers on a monthly or bimonthly basis. Revenues for energy delivered to customers between the last billing date and the end of the year are estimated and reflected in the accompanying financial statements under the caption unbilled revenues.

The Department's customer base comprises four identifiable groups, which accounted for electric energy sales as follows:

	2003	2002
Residential	36.1 %	37.6 %
Commercial	44.2	42.3
Industrial	10.5	11.2
Governmental	9.2	8.9
	100.0 %	100.0 %

Nonexchange Transactions–Capital contributions and grants in the amount of $26.1 million and $13.0 million are reported for 2003 and 2002, respectively, on the statements of revenues, expenses, and changes in equity as nonoperating revenues from nonexchange transactions. In-kind capital contributions are recognized at fair value and are generally based either on the internal engineer's estimate of the current cost of comparable plant in service or the donor's actual cost.

Use of Estimates–The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the financial statements. The Department used significant estimates in determining reported unbilled revenues, energy contract assets and liabilities, accumulated provision for injuries and damages, allowance for doubtful accounts, accrued sick leave, and other contingencies. Actual results may differ from those estimates.

Significant Risk and Uncertainty–The Department is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include prices on the wholesale markets for short-term power transactions; interest rates; water conditions, weather, and natural disaster related disruptions; terrorism; collective bargaining labor disputes; fish and other Endangered Species Act ("ESA") issues; Environmental Protection Agency ("EPA") regulations; federal government regulations or orders concerning the operations, maintenance, and/or licensing of hydroelectric facilities; other governmental regulations; the deregulation of the electrical utility industry; and the costs of constructing transmission facilities that may be incurred as part of a regional transmission system.

Reclassifications–Certain 2002 account balances have been reclassified to conform to the 2003 presentation.

2. UTILITY PLANT

Utility plant in service at original cost, excluding land, at December 31, 2003, consists of:

	Hydraulic Production	Transmission	Distribution	General	Total
Beginning balance	$527,022,003	$139,951,608	$1,068,429,863	$297,080,941	$ 2,032,484,415
Capital acquisitions	36,972,921	6,406,711	68,394,546	16,843,145	128,617,323
Dispositions	(5,279,046)	(295,449)	(2,637,960)	(5,352,650)	(13,565,105)
Transfers and adjustments	4,051	(82,112)	5,222,173		5,144,112
	558,719,929	145,980,758	1,139,408,622	308,571,436	2,152,680,745
Less accumulated depreciation	(279,420,331)	(62,863,342)	(410,090,161)	(162,604,679)	(914,978,513)
Ending balance	$279,299,598	$ 83,117,416	$ 729,318,461	$145,966,757	$ 1,237,702,232

FERC licenses for owned hydraulic production facilities consist of:

Project	License Issued	License Effective	License Expires	Years Licensed
Boundary	10/01/1961	10/01/1960	10/01/2011	50
Gorge	05/16/1995	05/01/1995	05/01/2025	30
Diablo	05/16/1995	05/01/1995	05/01/2025	30
Ross	05/16/1995	05/01/1995	05/01/2025	30
Newhalem	02/07/1997	02/01/1997	02/01/2027	30
South Fork Tolt	03/29/1984	03/01/1984	03/01/2024	40

See *Endangered Species* within Note 13 for contingent relicensing requirements regarding Boundary relicensing.

3. CASH AND EQUITY IN POOLED INVESTMENTS AND INVESTMENTS

Cash and Equity in Pooled Investments and Investments– The City pools and invests all temporary cash surpluses for City departments. These residual investments may consist of deposits with qualified public depositories; obligations of the United States or its agencies or wholly owned corporations; obligations of eligible government-sponsored enterprises; and certain bankers' acceptances, commercial paper, general obligation bonds or warrants, repurchase agreements, reverse repurchase agreements, mortgage-backed securities, derivative-based securities, and participation in the State Treasurer's local government investment pool, and are in accordance with the Revised Code of Washington 35.39.032 and 39.58. According to City policy, securities purchased will have a maximum maturity of no longer than 15 years, and the average maturity of all securities owned should be no longer than five years. Also by City policy, the City may operate a securities lending program, and there were transactions during 2003 and 2002. There were no securities lending program transactions outstanding at year-end 2003 or 2002. The Department's equity in residual investments is reflected as cash and equity in pooled investments. The City's residual investment pool did not include reverse repurchase agreements at the end of 2003 or 2002; the City did not invest in such instruments during 2003 or 2002. Derivative-based securities were owned by the City pool during 2003 and 2002 and at both year ends. These securities were callable U.S. government agency instruments. Earnings and adjustments to fair value from the investment pool are prorated monthly to City departments based on the average daily cash balances of participating funds.

Banks or trust companies acting as the City's agents hold most of the City's investments in the City's name, with respect to credit risk as defined in GASB Statement No. 3, *Deposits with Financial Institutions, Investments (including Repurchase Agreements), and Reverse Repurchase Agreements.* All transactions are executed with authorized security dealers, financial institutions, or securities lending agents on a delivery versus payment basis.

The first $100,000 of bank deposits are federally insured. The Washington State Public Deposit Protection Commission ("PDPC") collateralizes deposits in excess of $100,000. The PDPC is a multiple financial institution collateral pool. There is no provision for the PDPC to make additional pro rata assessments if needed to cover a loss. Therefore, the PDPC protection is of the nature of collateral, not of insurance.

Securities with maturities exceeding three months at time of purchase are reported at fair value on the balance sheets; the net increase (decrease) in the fair value of those investments is reported as part of investment income. At December 31, changes in the fair value of investments resulted in an unrealized loss of $1.7 million for 2003 and an unrealized gain of $.8 million for 2002.

The cash pool operates like a demand deposit account in that all City departments, including the Department, may deposit cash at any time and can also withdraw cash out of the pool without prior notice or penalty. Accordingly, the statements of cash flows reconcile to cash and equity in pooled investments.

Cash and cash equivalents included in cash and equity in pooled investments at December 31 consists of:

	2003	2002
Restricted assets:		
Municipal Light and Power Bond		
Reserve Account	$14,486,404	$24,998,402
Bond proceeds and other	1,348,695	51,152,110
Special deposits and other	4,158,641	4,639,446
	19,993,740	80,789,958
Current assets	1,700,368	11,425,127
	$21,694,108	$92,215,085

Equity in pooled investments and U.S. government securities are reported at fair values based on quoted market prices for those or similar securities and are as follows at December 31:

	2003	2002
Restricted assets:		
Municipal Light & Power Bond		
Reserve Account:		
Equity in pooled investments	$65,136,266	$ 52,976,598
Bond proceeds and other:		
Equity in pooled investments	6,057,692	107,115,402
	71,193,958	160,092,000
Current assets:		
Equity in pooled investments	7,646,802	23,269,386
	$78,840,760	$183,361,386

4. ACCOUNTS RECEIVABLE

Accounts receivable at December 31 consists of:

	Retail Power	Wholesale Power	Fees, Grants, and Other	Interfund	Due from Other Governments	Total
2003:						
Accounts receivable	$59,257,341	$23,897,296	$5,125,240	$1,458,279	$5,481,358	$95,219,514
Less allowance for doubtful accounts	(8,850,000)	(2,570,000)	(1,210,000)			(12,630,000)
	$50,407,341	$21,327,296	$3,915,240	$1,458,279	$5,481,358	$82,589,514
2002:						
Accounts receivable	$57,304,001	$13,950,626	$4,693,499	$2,626,871	$1,460,052	$80,035,049
Less allowance for doubtful accounts	(4,000,000)	(1,520,000)	(1,170,000)			(6,690,000)
	$53,304,001	$12,430,626	$3,523,499	$2,626,871	$1,460,052	$73,345,049

5. SHORT-TERM POWER CONTRACTS AND DERIVATIVE INSTRUMENTS

The Department enters into forward contracts to purchase or sell energy. Under these forward contracts, the Department commits to purchase or sell a specified amount of energy at a specified time, or during a specified time in the future. Certain of the forward contracts are considered derivatives. These derivatives, along with other short-term power transactions, are entered into solely for the purpose of managing the Department's resources to meet load requirements. The Department does not take market positions in anticipation of generating revenue, with the exception of strictly limited and closely monitored intraday and interday trading to find value in the Department's portfolio by creating and selling services that use the flexibility of the Department's owned hydro system and to take advantage of owned hydro storage. Power transactions in response to forecasted seasonal resource and demand variations require approval by the Department's Risk Management Committee. Fluctuations in annual precipitation levels and other weather conditions materially affect the energy output from the Department's hydroelectric facilities and some of its long-term purchased hydroelectric power agreements. Demand fluctuates with weather and local economic conditions. Accordingly, short-term power transactions required to manage resources to meet the Department's load and dispose of surplus energy may vary from year to year.

Information related to the Department's short-term wholesale power contracts outstanding as of December 31 are as follows:

	2003	2002
Wholesale power purchases outstanding	$1,911,881	$2,940,900
Megawatt hours ("MWh")	54,725	88,800
Average contract purchase cost per MWh	$34.94	$33.12
Wholesale power sales outstanding	$74,967,251	$54,206,420
MWh	2,329,107	1,570,000
Average contract sales price per MWh	$32.19	$34.53

The fair market value of derivative instruments held by the department as of December 31 is as follows:

	2003	2002
Assets:		
Energy contracts:		
Forward energy sales	$5,492,487	$1,452,182
Forward energy purchases	3,891	396,168
Other deferred charges—net:		
Unrealized losses from fair valuation of:		
Forward energy sales		3,935,769
Forward energy purchases	163,664	
	$5,660,042	$5,784,119
Liabilities:		
Energy contracts:		
Forward energy sales	$3,377,111	$5,387,951
Forward energy purchases	167,555	
Deferred credits:		
Unrealized gains from fair valuation of:		
Forward energy sales	2,115,376	
Forward energy purchases		396,168
	$5,660,042	$5,784,119

6. LONG-TERM AND SHORT-TERM DEBT

At December 31, the Department's long-term and short-term debt consisted of the following:

				2003	2002
LONG-TERM					
Prior Lien Bonds:					
2003	ML&P Improvement and Refunding Revenue Bonds	4.000% to 6.000%	due 2028	$ 251,850,000	$ –
2002	ML&P Refunding Revenue Bonds	3.000% to 4.500%	due 2014	85,275,000	87,735,000
2001	ML&P Improvements and Refunding Revenue Bonds	5.000% to 5.500%	due 2026	503,700,000	503,700,000
2000	ML&P Revenue Bonds	4.500% to 5.625%	due 2025	98,830,000	98,830,000
1999	ML&P Revenue Bonds	5.000% to 6.000%	due 2024	158,000,000	158,000,000
1998B	ML&P Revenue Bonds	4.750% to 5.000%	due 2024	90,000,000	90,000,000
1998A	ML&P Refunding Revenue Bonds	4.500% to 5.000%	due 2020	102,120,000	102,835,000
1997	ML&P Revenue Bonds	5.000% to 5.125%	due 2022	29,070,000	30,000,000
1996	ML&P Revenue Bonds	5.250% to 5.625%	due 2021	28,230,000	29,135,000
1995B	ML&P Revenue Bonds	4.050% to 4.800%	due 2005	456,000	456,000
1995A	ML&P Revenue Bonds	5.000% to 5.700%	due 2020	53,875,000	55,815,00
1994	ML&P Revenue Bonds	6.00%	due 2004	3,450,000	6,280,000
1993	ML&P Revenue & Refunding Revenue Bonds	2.200% to 5.500%	due 2004	20,215,000	166,360,000
				1,425,071,000	1,329,146,000
Subordinate Lien Bonds:					
1996	ML&P Adjustable Rate Revenue Bonds	variable	due 2021	18,455,000	19,140,000
1993	ML&P Adjustable Rate Revenue Bonds	variable	due 2018	17,800,000	18,700,000
1991B	ML&P Adjustable Rate Revenue Bonds	variable	due 2016	16,500,000	17,500,000
1991A	ML&P Adjustable Rate Revenue Bonds	variable	due 2016	25,000,000	25,000,000
1990	ML&P Adjustable Rate Revenue Bonds	variable	due 2015	18,700,000	19,700,000
				96,455,000	100,040,000
City of Seattle:					
2003	Note payable	5.000%	due 2005	5,158,625	
	Total long-term debt			$ 1,526,684,625	$ 1,429,186,000
SHORT-TERM					
Revenue Anticipation Notes:					
2001	ML&P Revenue Anticipation Notes	4.500% and 5.250%	due 2003	$ –	$ 182,210,000
2002	ML&P Revenue Anticipation Notes	2.500%	due 2003		125,000,000
					307,210,000
City of Seattle:					
2003	Short-term borrowings—City of Seattle	variable	due 2004	70,000,000	
	Total short-term debt			$ 70,000,000	$ 307,210,000

The Department had the following activity in long-term debt during 2003:

	Balance at 12/31/02	Additions	Reductions	Balance at 12/31/03	Current Portion
Prior Lien Bonds	$1,329,146,000	$251,850,000	$(155,925,000)	$1,425,071,000	$49,705,000
Subordinate Lien Bonds	100,040,000		(3,585,000)	96,455,000	4,115,000
Note payable—City of Seattle		5,565,000	(406,375)	5,158,625	
	$1,429,186,000	$257,415,000	$(159,916,375)	$1,526,684,625	$53,820,000

Prior Lien Bonds–In August 2003, the Department issued $251.8 million in ML&P Improvement and Refunding Revenue Bonds that bear interest at rates ranging from 4.00% to 6.00% and mature serially from November 1, 2004, through 2025. Term bonds mature on November 1, 2028. The arbitrage yield for the 2003 bonds is 4.335%. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the bonds, produces an amount equal to the issue price of the bonds. Proceeds were used to finance certain capital improvements and conservation programs and to defease certain outstanding prior lien bonds. The debt service on the improvement and refunding bonds requires a cash flow of $393.4 million, including $141.5 million in interest. The difference between the cash flows required to service the old and the new debt and complete the refunding totaled $5.8 million, and the aggregate economic gain totaled $5.4 million at net present value. The loss on refunding was $15.0 million and is being amortized using the effective interest method over the life of the new bonds. The unamortized balance of the loss on refunding at December 31, 2003, was $14.0 million.

In December 2002, the Department issued $87.7 million in ML&P Refunding Revenue Bonds that bear interest at rates ranging from 3.00% to 4.50% and mature serially from December 1, 2003, through 2014. The arbitrage yield for the 2002 bonds is 3.427%. Proceeds were used to defease certain outstanding prior lien bonds. The debt service on the refunding bonds requires a cash flow of $110.4 million, including $22.7 million in interest. The difference between the cash flows required to service the old and the new debt and complete the refunding totaled $5.1 million, and the aggregate economic gain totaled $5.97 million at net present value. The loss on refunding was $8.9 million and is being amortized using the effective interest method over the life of the new bonds. The unamortized balance of the loss on refunding at December 31, 2003 and 2002, was $7.8 million and $8.8 million, respectively.

Future debt service requirements for prior-lien bonds are as follows:

Year Ending December 31	Principal Redemptions	Interest Requirements	Total
2004	$ 49,705,000	$ 73,667,837	$ 123,372,837
2005	52,781,000	71,551,006	124,332,006
2006	56,225,000	69,253,098	125,478,098
2007	58,945,000	66,524,336	125,469,336
2008	62,055,000	63,416,923	125,471,923
2009 – 2013	330,545,000	265,864,239	596,409,239
2014 – 2018	342,990,000	175,408,036	518,398,036
2019 – 2023	309,815,000	86,824,202	396,639,202
2024 – 2028	162,010,000	15,435,510	177,445,510
	$1,425,071,000	$887,945,187	$2,313,016,187

The Department is required by ordinance to fund reserves for prior lien bond issues in an amount equal to the lesser of (a) the maximum annual debt service on all bonds secured by the reserve account or (b) the maximum amount permitted by the Internal Revenue Code ("IRC") of 1986 as a reasonably required reserve or replacement fund. Upon issuance of the 2003 bonds, the maximum annual debt service on prior lien bonds remained at $125.5 million. The IRC's requirement decreased from $113.5 million to $113.3 million. At December 31, 2003, the balance in the reserve account was $79.6 million at fair value. The reserve must be fully funded by August 1, 2008.

In addition to the 2003 refunding revenue bonds, the Department has previously issued several refunding revenue bonds for the purpose of defeasing certain outstanding prior lien bonds. Refunding revenue bonds were also issued in 2002, 2001, 1998, and 1993. Proceeds from the refunding bonds were placed in separate irrevocable trusts to provide for all future debt service payments on the bonds defeased. Accordingly, neither the assets of the respective trust accounts nor the liabilities for the defeased bonds are reflected in the Department's financial statements. The bonds defeased in 2003 and 2002 were called in full on November 1, 2003. The bonds defeased in 1998 and 1993 had outstanding principal balances of $94.7 million and $4.3 million, respectively, as of December 31, 2003. Funds held in the respective trust accounts on December 31, 2003, are sufficient to service and redeem the defeased bonds.

***Subordinate Lien Bonds*–**The Department is authorized to issue a limited amount of adjustable rate revenue bonds, which are subordinate to prior lien bonds with respect to claim on revenues. Subordinate lien bonds may be issued to the extent that the new bonds will not cause the aggregate principal amount of such bonds then outstanding to exceed the greater of $70 million or 15% of the aggregate principal amount of prior lien bonds then outstanding. Subordinate bonds may be remarketed daily, weekly, short-term, or long-term and may be converted to prior lien bonds when certain conditions are met.

In December 1996, the Department issued ML&P Adjustable Rate Revenue Bonds in the amount of $19.8 million, subject to a mandatory redemption schedule spanning the period from June 1, 2002, to June 1, 2021. The bonds had an outstanding balance of $18.5 million at December 31, 2003. These bonds were marketed weekly at an interest rate ranging from 0.60% to 1.30% during 2003. Proceeds were used to finance a portion of the capital improvement and conservation program.

The 1990 bonds and 1991 Series B bonds were marketed on a short-term basis during 2003, with interest rates ranging from 0.75% to 1.30%. The 1990 bonds and the 1991 Series B bonds had an outstanding balance of $18.7 million and $16.5 million, respectively, at December 31, 2003.

The 1991 Series A bonds and the 1993 bonds were priced weekly at interest rates from 0.64% to 1.23% in 2003. The 1991 Series A bonds and the 1993 bonds had an outstanding balance of $25.0 million and $17.8 million, respectively, at December 31, 2003.

Future debt service requirements on the subordinate lien bonds, based on 2003 end of year actual interest rates ranging from 0.90% to 1.06% through year 2021, are as follows:

Year Ending December 31	Principal Redemptions	Interest Requirements	Total
2004	$ 4,115,000	$1,014,316	$ 5,129,316
2005	4,445,000	945,622	5,390,622
2006	4,775,000	888,514	5,663,514
2007	5,305,000	839,458	6,144,458
2008	5,840,000	786,227	6,626,227
2009 – 2013	36,530,000	2,926,206	39,456,206
2014 – 2018	31,380,000	871,852	32,251,852
2019 – 2021	4,065,000	64,381	4,129,381
	$96,455,000	$8,336,576	$104,791,576

***Revenue Anticipation Notes*–**In November 2002, the Department issued $125.0 million in ML&P Revenue Anticipation Notes ("RANs") at an interest rate of 2.50% with an arbitrage yield of 1.49%. The 2002 RANs matured in November 2003.

In March 2001, the Department issued $182.2 million in ML&P RANs. $136.7 million of the 2001 RANs had an interest rate of 4.50%, and $45.5 million had an interest rate of 5.25%. The arbitrage yield of the 2001 RANs was 3.75%. The 2001 RANs matured in March 2003.

All RANs were special limited obligations of the Department payable from and secured by gross revenues. Proceeds were used to finance operating expenses for each respective year. The RANs were on a lien subordinate to prior lien bonds and subordinate lien bonds; there was no reserve account securing repayment, and there was no debt service coverage requirement. No debt service requirements are outstanding for the RANs as of December 31, 2003.

Fair Value–The fair value of the Department's bonds and RANs is estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Department for debt of the same remaining maturities. Carrying amounts and fair values are as follows at December 31:

	2003 Carrying Amount	2003 Fair Value	2002 Carrying Amount	2002 Fair Value
Long-term debt:				
Prior lien bonds	$1,453,551,784	$1,528,392,143	$1,344,779,509	$1,407,056,096
Subordinate lien bonds	96,213,769	96,455,000	99,780,903	100,040,000
RANs			308,963,171	309,942,021
	$1,549,765,553	$1,624,847,143	$1,753,523,583	$1,817,038,117

Amortization–Bond issue costs, discounts, and premiums are amortized using the effective interest method over the term of the bonds.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt is amortized as a component of interest expense using both the straight-line and effective interest methods over the terms of the issues to which they pertain. Deferred refunding costs amortized to interest expense totaled $5.8 million in 2003 and $4.2 million in 2002. Deferred refunding costs in the amount of $38.5 million and $40.3 million are reported as a component of long-term debt in the 2003 and 2002 balance sheets, respectively.

Note Payable–In 2003, the Department purchased real estate property for a potential future substation from the City of Seattle Department of Parks and Recreation at a price of $5.6 million and financed it via a note payable to the Department of Parks and Recreation at 5%, maturing in July 2005. Debt service requirements for this note payable to maturity are:

Year Ending December 31	Principal Redemptions	Interest Requirements	Total
2003	$ 406,375	$ -	$ 406,375
2004		257,932	257,932
2005	5,158,625	257,931	5,416,556
	$5,565,000	$515,863	$6,080,863

Short-Term Borrowings–In late December 2001, the City of Seattle authorized an interfund loan (note payable) to the Department from the City's Consolidated (Residual) Cash Portfolio in an amount up to $110.0 million, of which $100 million was outstanding as of December 31, 2001. The purpose of the note payable was for working capital and it was due on or before March 31, 2003. The loan was repaid on January 1, 2002, and was carried as a negative operating cash balance during part of 2002. The loan was repaid in November 2002 with the 2002 RAN proceeds and was carried as a negative operating cash balance until maturity in March 2003.

Ordinance No. 121154 provided for a new interfund loan up to $50 million for working capital purposes. The same ordinance authorized an additional interfund loan up to $100 million beginning November 2003, expiring in December 2004. The amount outstanding as of December 31, 2003, was $70 million. The interest rate for the note payable for each month during 2003 was equal to the rate of return earned for each respective month by the City's Consolidated (Residual) Cash Portfolio. The loan will be carried forward as a negative operating cash balance until maturity.

7. SEATTLE CITY EMPLOYEES' RETIREMENT SYSTEM

The Seattle City Employees' Retirement System ("SCERS") is a single-employer defined benefit, public employee retirement system, covering employees of the City and administered in accordance with Chapter 41.28 of the Revised Code of Washington and Chapter 4.36 of the Seattle Municipal Code. SCERS is a pension trust fund of the City.

All employees of the City are eligible for membership in SCERS with the exception of uniformed police and fire personnel who are covered under a retirement system administered by the state of Washington. Employees of Metro and the King County Health Department who established membership in SCERS when these organizations were City departments were allowed to continue their SCERS membership. As of December 31, 2003, there were 4,876 retirees and beneficiaries receiving benefits and 8,382 active members of SCERS. In addition, 1,389 vested terminated employees were entitled to future benefits, and 193 terminated employees had restored their contributions due to the provisions of the portability statutes and may be eligible for future benefits.

SCERS provides retirement, death, and disability benefits. Retirement benefits vest after five years of credited service, while death and disability benefits vest after 10 years of service. Retirement benefits are calculated as 2% multiplied by years of creditable service, multiplied by average salary, based on the highest 24 consecutive months, excluding overtime. The benefit is actuarially reduced for early retirement.

Actuarially recommended contribution rates both for members and for the employer were 8.03% of covered payroll during 2003 and 2002.

Under the authority of the state and City, SCERS operates a securities lending program, and there were transactions during 2003 and 2002. SCERS has had no losses resulting from a default, and SCERS did not have negative credit exposure at December 31, 2003 or 2002.

SCERS issues stand-alone financial statements that may be obtained by writing to the Seattle City Employees' Retirement System, 801 Third Avenue, Suite 300, Seattle, Washington 98104; telephone: (206) 386-1292.

Employer contributions for the City were $34.2 million and $36.6 million in 2003 and 2002, respectively, and the annual required contributions were made in full. The recent performance of the stock market has effected the Unfunded Actuarial Accrued Liabilities ("UAAL") of SCERS. It is not known whether employer contributions will be necessary in the foreseeable future to fund a portion of SCERS' UAAL.

Actuarial Data	
Valuation date	January 1, 2002
Actuarial cost method	Entry age
Amortization method	Level percent
Remaining amortization period	33.7 years
Amortization period	Open
Asset valuation method	Market

Actuarial Assumptions*	Percentage
Investment rate of return	8.00%
Projected general wage increases	4.50
Cost-of-living year-end bonus dividend	0.67

* Includes price inflation at 4.0%.

Schedule of funding progress for the City (dollar amounts in millions):

Actuarial Valuation Date January 1, [5]	Actuarial Value of Assets (a)	Actuarial Accrued Liabilities ("AAL") Entry Age [1] (b)	Unfunded AAL ("UAAL") [2] (b-a)	Funding Ratio (a/b)	Covered Payroll [3] (c)	UAAL or Excess as a Percentage of Covered Payroll ((b-a)/c)
2000	$1,582.7	$1,403.1	$(179.6)	112.8 %	$370.4	(48.5)%
2001[4]	1,493.1	1,490.3	(2.8)	100.2	405.0	(.7)
2002	1,383.7	1,581.4	197.7	87.5	405.1	48.8

(1) Actuarial present value of benefits less actuarial present value of future normal costs based on entry age actuarial cost method.

(2) Actuarial accrued liabilities less actuarial value of assets; funding excess if negative.

(3) Covered payroll includes compensation paid to all active employees on which contributions are calculated.

(4) Information for January 1, 2001, was provided by an actuarial study, rather than a full valuation.

(5) Actuarial valuation information for January 1, 2003, is not available. Actuarial valuations will be performed every two years and the next regular valuation will be as of January 1, 2004.

8. DEFERRED COMPENSATION

The Department's employees may contribute to the City's Voluntary Deferred Compensation Plan (the "Plan"). The Plan, available to City employees and officers, permits participants to defer a portion of their salary until future years. The Plan administrator was Fidelity Investments in 2003 and 2002. The deferred compensation is paid to participants and their beneficiaries upon termination, retirement, death, or unforeseeable emergency.

Effective January 1, 1999, the Plan became an eligible deferred compensation plan under Section 457 of the IRC of 1986, as amended, and a trust exempt from tax under IRC Sections 457(g) and 501(a). The Plan is operated for the exclusive benefit of participants and their beneficiaries. No part of the corpus or income of the Plan shall revert to the City or be used for, or diverted to, purposes other than the exclusive benefit of participants and their beneficiaries.

The Plan is not reported in the financial statements of the City or the Department.

It is the opinion of the City's legal counsel that the City has no liability for investment losses under the Plan. Participants direct the investment of their money into one or more options provided by the Plan and may change their selection from time to time. By enrolling in the Plan, participants accept and assume all risks inherent in the Plan and its administration.

9. LONG-TERM PURCHASED POWER, EXCHANGES, AND TRANSMISSION

Bonneville Power Administration–The Department purchases electric energy from the U.S. Department of Energy, Bonneville Power Administration ("Bonneville") under the Block and Slice Power Sales Agreement, a 10-year contract that expires September 30, 2011. The agreement provides a block of power shaped to the Department's monthly net requirements, defined as the difference between projected monthly load and firm resources available to serve that load. Additional amounts of power will be purchased and received throughout the term of the contract under the Slice portion of the contract. The terms of the Slice product specify that the Department will receive a fixed percentage (4.6676%) of the actual output of the Federal Columbia River Power System. The cost of Slice power is based on the Department's same percentage (4.6676%) of the expected costs of the system and is subject to true-up adjustments based on actual costs. The true-up adjustment billed by Bonneville for federal fiscal year 2002 was $10.4 million and was deferred pending rate recovery of the amount due and $8.5 million was amortized in 2003; a true-up credit of $6.3 million for federal fiscal year 2003 was deferred as of December 31, 2003, and will be recognized during 2004. Bonneville rate adjustments will be passed through to retail electric customers in the form of rate adjustments in accordance with the rates ordinance. The actual amounts of firm and nonfirm energy available through the Slice product will vary with water conditions, federal generating capabilities, and fish and wildlife restoration requirements, and expected amounts available under critical water conditions in average megawatts ("aMW") are as follows:

	Block Power [1] aMW	Slice Power [2] aMW
2004	137	334
2005	146	334
2006	184	334
2007 - 2010	260	334
2011	170	334

[1] Amendment No. 6, Bonneville Block Power, September 2003.

[2] Slice power expected in critical water conditions.

Amendments to the contract through September 2003 provide that Bonneville will pay the Department for energy savings through specified programs. The conservation augmentation program provides funding from Bonneville for a portion of the Department's conservation costs in exchange for a reduction of the amount of power, by the amount of energy saved, that the Department will purchase from Bonneville. The conservation and renewables discount ("C&RD") program provides a Bonneville power bill credit for qualifying conservation, renewables, and low-income weatherization costs, and donations to qualifying organizations.

Information related to the programs is summarized as follows:

	Conservation Augmentation[1]			C&RD
Contract Year	Estimated Energy Savings (aMW)	Cash Receipts (Millions)	Revenues (Millions)	Revenues (Millions)
2002	8.46	$20.0	$3.3	$2.1
2003	8.75[2]	10.7	3.4	2.1
2004	7.76	8.6		
2005 – 2006	7.25	12.2		

[1] Cash receipts are being recognized over the life of the Bonneville contract. Revenues for 2002 included $0.7 million for 2001.

[2] Energy savings for 2003 have been submitted to Bonneville for audit.

Energy Northwest–In 1983, the Department entered into separate net billing agreements with Bonneville and Energy Northwest (formerly the Washington Public Power Supply System), a municipal corporation and joint operating agency of the state of Washington, with respect to sharing costs for the construction and operation of three nuclear generating plants. Under these agreements, the Department is unconditionally obligated to pay Energy Northwest a pro rata share of the total annual costs, including debt service, decommissioning costs, and asset retirement obligations, to finance the cost of construction, whether or not construction is completed, delayed, or terminated, or operation is suspended or curtailed. The net billing agreements provide that these costs be recovered through Bonneville rates. The Department pays the amounts billed by Bonneville directly to Energy Northwest until the payment obligation has been fulfilled for the year. The billings for the remainder of the year are then paid to Bonneville. One plant is in commercial operation. Construction of the other two plants has been terminated.

Lucky Peak–In 1984, the Department entered into a purchase power agreement with four irrigation districts to acquire 100% of the net output of a hydroelectric facility that began commercial operation in 1988 at the existing Army Corps of Engineers Lucky Peak Dam on the Boise River near Boise, Idaho. The irrigation districts are owners and license holders of the project, and the FERC license expires in 2030. The agreement, which expires in 2038, obligates the Department to pay all ownership and operating costs, including debt service, over the term of the contract, whether or not the plant is operating or operable.

To properly reflect its rights and obligations under this agreement, the Department includes as an asset and liability the outstanding principal of the project's debt, net of the balance in the project's reserve account. In July 2002, the project issued revenue refunding bonds totaling $55.985 million that bear interest ranging from 3.0% to 5.0% and mature July 1, 2004 through 2008.

British Columbia-Ross Dam–In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia will provide the Department with power equivalent to that which would result from an addition to the height of Ross Dam. The agreement was ratified through a treaty between Canada and the United States in the same year. The power is to be received for 80 years, and delivery of power began in 1986. The Department will make annual payments to British Columbia of $21.8 million through 2020, which represent the estimated debt service costs the Department would have incurred had the addition been constructed. The payments are charged to expense over a period of 50 years through 2035. The Department is also paying equivalent operation and maintenance costs. Payments made for this purpose totaled $164,181 and $163,997 in 2003 and 2002, respectively.

In addition to the direct costs of power under the agreement, the Department incurred costs of approximately $8.0 million in prior years related to the proposed addition and was obligated to help fund the Skagit Environmental Endowment Commission through four annual $1.0 million payments. These costs were deferred and are being amortized to purchased power expense over 35 years.

Klamath Falls–In November 2000, the Department and the City of Klamath Falls, Oregon, entered into an agreement for the purchase of energy and capacity from the Klamath Falls generation facility, a 500-MW plant consisting of two combustion turbines fueled by natural gas. Under the terms of the contract, the Department receives 100.0 MW of capacity from the project beginning on the project's date of commercial operation of July 29, 2001, through July 31, 2006, with an option to renew the contract for an additional five years. The Department may elect to displace all or a portion of the energy it is entitled to receive from this project in any given month and elected to take power from the plant for nine months in 2003 and 10 months in 2002. The Department assumes gas price and exchange rate risks for natural gas from Alberta, Canada. In April 2001, the Department entered into a separate contract that expired in December 2002 to swap variable Canadian dollar gas prices for a fixed U.S. dollar gas price, and recognized $12.3 million expenses in 2002.

Wind Generation–In October 2001, the Department entered into an agreement with PacifiCorp Power Marketing, Inc. (now PPM Energy) for the purchase of energy and associated environmental attributes primarily from the State Line Wind Project, a 300 MW facility located in Walla Walla County, Washington, and Umatilla County, Oregon. The aggregate maximum delivery rate per hour was 50 MW from January 1, 2002, through July 31, 2002, increasing to 100 MW from August 1, 2002, through December 31, 2021. The Department will also receive additional firm energy with an aggregate maximum delivery rate per hour of 50 MW from January 1, 2004, through June 30, 2004, and an additional 75 MW from July 1, 2004, through December 31, 2021, from the State Line Wind Project.

The Department entered into a related 10-year agreement to purchase integration and exchange services from PacifiCorp. PacifiCorp receives State Line Wind Project energy at the Wallula Substation in Walla Walla County, Washington, and stores, reshapes, and delivers the power two months later. The Department also entered into another related 20-year agreement to sell integration and exchange services to PPM Energy only when the Department does not receive 50 MW of contractually defined additional energy from the State Line Wind Project.

Other Long-Term Purchased Power Agreements–The Department also purchases energy from Public Utility Districts (the "PUDs") No. 1 of Pend Oreille County and No. 2 of Grant County, under agreements expiring August 1, 2005, and October 31, 2005, respectively; the Grand Coulee Project Hydroelectric Authority (the "GCPH Authority"), which includes the South, East, and Quincy Columbia Basin Irrigation Districts under 40-year agreements that expire from 2022 to 2026; the Department purchased power from the Columbia Storage Power Exchange until the agreement expired on March 31, 2003. Rates under the Grant County PUD and GCPH Authority contracts represent the share of the operating and debt service costs in proportion to the share of total energy to which the Department is entitled, whether or not these plants are operating or operable.

Three new contracts were executed in March 2002 with Grant County PUD to replace the contract expiring October 31, 2005. The agreements are effective November 1, 2005, and run concurrent with the term of the future federal relicense period.

Power received under long-term purchased power agreements in average annual megawatts ("aaMW") is as follows:

Long-Term Purchased Power	2003 aaMW	Percent of Total	2002 aaMW	Percent of Total
Bonneville Slice	390.9	50.1%	379.6	48.9%
Bonneville Block	147.1	18.8%	152.3	19.6%
Lucky Peak	33.4	4.3%	33.0	4.2%
British Columbia—Ross Dam	36.0	4.6%	33.9	4.4%
City of Klamath Falls	74.7	9.6%	81.0	10.4%
Wind generation	24.7	3.2%	12.2	1.6%
Pend Oreille County Public Utility District	5.4	0.7%	5.0	0.6%
Grant County Public Utility District	35.5	4.5%	37.3	4.8%
Grand Coulee Project Hydroelectric Authority	26.9	3.4%	28.3	3.6%
Columbia Storage Power Exchange	3.0	0.4%	11.3	1.5%
	70.8	9.0%	81.9	10.5%
	777.6	99.6%	773.9	99.6%
Other	3.2	0.4%	2.8	0.4%
	780.8	100.0%	776.7	100.0%
Peaking Capacity				
British Columbia—Ross Dam	130.0		141.0	

Transmission– In July 2000, the Department entered into an agreement with Bonneville for firm transmission service under Bonneville's open access transmission tariff from August 2000 through July 2025. In September 1994, the Department entered into an agreement with Bonneville for ownership of 160 MW of Bonneville's Pacific Northwest north-south AC Intertie for $34.3 million and annual operations costs. Other transmission contracts were executed in 1995 with Puget Sound Energy for transmission of South Fork Tolt power through 2020; in 1988 with Idaho Power for transmission of Lucky Peak power through December 2007; in 1983 with GCPH Authority for transmission of the output of the GCPH Authority's power plants over the 40-year terms of several related power contracts; and in 1983 as amended in 1990 with Avista for transmission of the power output of the Summer Falls and Main Canal projects through October 2005.

Estimated Future Payments Under Purchased Power And Transmission Contracts– The Department's estimated payments under its contracts with Bonneville, the PUDs, irrigation districts, Lucky Peak Project, British Columbia - Ross Dam, Klamath Falls, PPMI and PacifiCorp for wind energy and net integration and exchange services, and for transmission for the period from 2004 through 2065, undiscounted, are:

Year Ending December 31,	Estimated Payments
2004	$ 275,405,308
2005	284,191,348
2006	283,463,321
2007	280,518,410
2008	280,447,450
2009 – 2013[1]	927,524,568
2014 – 2018	474,569,397
2019 – 2023	378,175,606
2024 – 2028[2]	121,453,263
2029 – 2033	27,453,994
2034 – 2038	15,533,661
2039 – 2065[3]	4,504,416
	$3,353,240,742

(1) Bonneville Block and Slice contract expires September 30, 2011.

(2) Bonneville transmission contract expires July 31, 2025.

(3) BC Hydro—Ross Dam operations and maintenance costs estimated at $166,830 per year from 2039 to 2065.

The effects of a proposed Regional Transmission Organization and other changes that could occur to transmission as a result of FERC's proposed Standard Market Design are not reflected in the estimated future payments.

Payments under these long-term power contracts totaled $251.8 million and $238.2 million in 2003 and 2002, respectively. Payments under these transmission contracts totaled $30.0 million and $30.7 million in 2003 and 2002, respectively.

Power Exchanges–Northern California Power Agency ("NCPA") and the Department executed a long-term Capacity and Energy Exchange Agreement in March 1993. NCPA provides a total of 91,584 MWh, or an option of 108,696 MWh under conditions specified in the contract, of exchange power to the Department from December through April. The Department provides a total of 90,580 MWh of exchange power to NCPA from June through October 15. The agreement may be terminated in May 2014 with seven years advance written notice by either party.

The Tacoma-Seattle Energy Coordination and Exchange Agreement was executed in October 1991. The Agreement provided for the firm exchange of 50 average megawatts of energy from Tacoma to Seattle each August and from Seattle to Tacoma each October until expiration in October 2003.

10. OTHER ASSETS

Other assets comprise deferred energy management costs and other deferred charges. Deferred energy management costs-net represent programmatic conservation costs. Seattle City Council-passed resolutions authorize the debt financing and deferral of programmatic conservation costs not funded by third parties and incurred by the Department. These costs are to be recovered through rates over 20 years.

Deferred power costs incurred for short-term wholesale power purchases during 2001 are expected to be recovered through rates at $8.3 million per month through 2004, pursuant to SFAS No. 71 and Ordinance 120385.

Other deferred charges and assets-net consist of the following at December 31:

	2003	2002
Unrealized losses from fair valuations of:		
Short-term forward sales of electric energy	$ –	$ 3,935,769
Short-term forward purchases of electric energy	163,664	
BPA Slice contract true-up payment	1,898,666	10,442,663
British Columbia—Ross Dam	40,321,500	31,448,059
Puget Sound Energy interconnection and substation	1,862,370	2,005,283
Studies, surveys, and investigations	533,435	406,808
Skagit Environmental Endowment	1,997,712	2,115,225
Endangered Species Act	1,341,435	
Real estate and conservation loans receivable	473,169	657,441
Unamortized debt expense	5,315,921	4,461,726
General work in process to be billed	1,035,352	1,036,565
Other	1,349,997	153,596
	$56,293,221	$56,663,135

Unamortized charges for the deferral of debt payments relating to Ross Dam will be amortized between 2021 and 2035. The remaining components of other assets, excluding billable work in progress, are being amortized to expense over four to 36 years.

11. DEFERRED CREDITS

Deferred credits consists of the following at December 31:

	2003	2002
BPA conservation augmentation	$24,200,537	$16,663,356
BPA Slice true-up	6,348,625	
Unrealized gains from fair valuation of short-term forward sales of electric energy	2,115,376	396,168
Levelized lease payments for Seattle office	919,404	947,360
Prepaid capital fees	1,420,338	1,732,238
Customer deposits—sundry sales	1,107,614	1,070,531
Prepaid grants	571,624	164,785
Other	286,691	242,274
	$36,970,209	$21,216,712

12. PROVISION FOR INJURIES AND DAMAGES

The Department is self-insured for casualty losses to its property, including for terrorism, environmental cleanup, and certain losses arising from third-party damage claims. The Department establishes liabilities for claims based on estimates of the ultimate cost of claims. The length of time for which such costs must be estimated varies depending on the nature of the claim. Actual claims costs depend on such factors as inflation, changes in doctrines of legal liability, damage awards, and specific incremental claim adjustment expenses. Claims liabilities are recomputed periodically using actuarial and statistical techniques to produce current estimates, which reflect recent settlements, claim frequency, industry averages, City-wide cost allocations, and economic and social factors. Liabilities for lawsuits, claims, and workers' compensation were discounted over a period of 15 to 17 years in 2003 and 2002 at the City's average annual rate of return on investments, which was 3.161% in 2003 and 4.238% in 2002. Liabilities for environmental cleanup and for casualty losses to the Department's property do not include claims that have been incurred but not reported and are not discounted due to uncertainty with respect to regulatory requirements and settlement dates, respectively.

The Lower Duwamish Waterway was designated a federal Superfund site by the EPA in 2001 for contaminated sediments. The City of Seattle is one of four parties who signed an Administrative Order on Consent with the EPA and State Department of Ecology to conduct a remedial investigation/feasibility study to prepare a site remedy. The Department is considered a potentially responsible party for contamination in the Duwamish River due to land ownership or use of property located along the river. The estimated liabilities related to this site totaled $5.7 million and $2.5 million for 2003 and 2002, respectively.

The schedule below presents the changes in the provision for injuries and damages:

	2003	2002
Unpaid claims at January 1	$10,476,242	$ 8,090,816
Payments	(2,391,275)	(1,474,499)
Incurred claims	5,572,574	3,859,925
Unpaid claims at December 31	$13,657,541	$10,476,242

The provision for injuries and damages is included in current and noncurrent liabilities as follows:

	2003	2002
Noncurrent liabilities	$10,491,426	$ 7,895,490
Accounts payable and other	3,166,115	2,580,752
	$13,657,541	$10,476,242

13. COMMITMENTS AND CONTINGENCIES

Operating Leases–In December 1994, the City entered into an agreement on behalf of the Department for a 10-year lease of office facilities in downtown Seattle commencing February 1, 1996. In early 1996, the City purchased the building in which these facilities are located, thus becoming the Department's lessor. In addition, the Department leases equipment and smaller facilities for office and storage purposes through long-term operating lease agreements. Expense under the leases totaled $3.8 million and $3.5 million in 2003 and 2002, respectively.

Minimum payments under the operating leases are:

Year Ending December 31	Minimum Payments
2004	$3,797,985
2005	3,809,334
2006	511,079
2007	113,588
2008	84,078
2009	1,360
	$8,317,424

***Skagit Mitigation*–**In 1995, FERC issued a license for operation of the Skagit Project in effect through 2025. As a condition of the license, the Department has taken and will continue to take various mitigating actions relating to fisheries, wildlife, erosion control, archeology, historic preservation, recreation, and visual quality issues. The mitigation cost was estimated at December 31, 2003, to be $47.7 million, of which $45.0 million has been expended.

***2004 Program*–**The estimated financial requirement for the Department's 2004 capital improvement and conservation program is $130.4 million, and the Department has substantial contractual commitments relating thereto.

***Project Impact Payments*–**Effective November 1999, the Department committed to pay a total of $11.6 million and $7.8 million over 10 years ending in 2008 to Pend Oreille County and Whatcom County, respectively, for impacts on county governments from the operations of the Department's hydroelectric projects. The payments compensate the counties, and certain school districts and towns located in these counties, for loss of revenues and additional financial burdens associated with the projects. The Boundary Project located on the Pend Oreille River affects Pend Oreille County, and Skagit River hydroelectric projects affect Whatcom County. The combined impact compensation, including annual inflation factor of 3.1%, and retroactive payments totaled $1.1 million to Pend Oreille County in each year and $0.7 million and $0.8 million to Whatcom County in 2003 and 2002, respectively.

***Endangered Species*–**Several fish species that inhabit waters where hydroelectric projects are owned by the Department or where the Department purchases power have been listed under the Endangered Species Act as threatened or endangered. On the Columbia River system, the National Oceanographic Atmospheric Administration Fisheries has developed a broad species recovery plan for listed salmon and steelhead, including recommendations for upstream and downstream fish passage requirements. These requirements include minimum flow targets for the entire Columbia Basin designed to maximize the survival of migrating salmon and steelhead. As a result, the Department's power generation at its Boundary Project is reduced in the fall and winter when the region experiences its highest sustained energy demand. The Boundary Project's firm capability is also reduced. Other Department-owned projects are not affected by the Columbia River. In Puget Sound, both bull trout and chinook salmon have been listed as threatened. Bull trout are present in the waters of Skagit, Tolt, and Cedar River projects and chinook salmon occur downstream. While it is unknown how other listings will affect the Department's hydroelectric projects and operations, the Department is carrying out an ESA Early Action program in cooperation with agencies, tribes, local governments, and salmon groups that will assist in the recovery of bull trout and chinook salmon on the Skagit and Tolt. On the Cedar, the Department's activities are covered by a Habitat Conservation Plan that authorizes operations with regard to all listed species. Hydroelectric projects must also satisfy the requirements of the Clean Water Act in order to obtain a FERC license. The application for the new boundary license is due October 2009 and may entail additional requirements for endangered species for which the full extent is not known at this time.

***Streetlight Litigation*–**In November 2003, the Washington Supreme Court ruled that a 1999 ordinance related to inclusion of streetlight costs in the general rate base for Seattle customers was unlawful. As a result of this decision, the Department resumed billing the City of Seattle for streetlight costs. At December 31, 2003, the remedies phase of this case was still being litigated. On May 21, 2004, trial court proceedings resulted in a ruling that the Department be required to refund the amount collected from ratepayers since 2000 attributable to streetlight costs. However, the ruling also provides that the City of Seattle general fund will have to repay the Department for the streetlight bills that would have been sent over the same period. Apart from the administrative costs that may be involved, the Department does not believe that the court's order will result in a negative impact to the Department's financial position or operations; however, the case is subject to appeal, which could change these trial court rulings.

***Other Contingencies*–**In the normal course of business, the Department has various other legal claims and contingent matters outstanding. The Department believes that any ultimate liability arising from these actions will not have a material adverse impact on the Department's financial position or operations.

FINANCIAL SUMMARY (Unaudited)

Years ended December 31,	2003	2002	2001	2000	1999
BALANCE SHEETS					
Assets					
Utility plant, net	$ 1,390,857,362	$ 1,345,435,582	$ 1,300,035,639	$ 1,242,167,417	$ 1,156,236,906
Capitalized purchased power commitment	45,130,152	50,279,621	56,947,942	65,855,587	73,854,788
Restricted assets	159,432,145	240,881,958	243,432,809	73,780,909	62,528,127
Current assets	178,234,062	190,990,153	155,835,416	146,129,452	178,517,210
Other assets	286,898,970	377,433,352	454,709,681	113,755,299	94,727,946
Total assets	$ 2,060,552,691	$ 2,205,020,666	$ 2,210,961,487	$ 1,641,688,664	$ 1,565,864,977
Liabilities & Equity					
Long-term debt, net	$ 1,462,609,162	$ 1,365,447,879	$ 1,683,202,477	$ 1,023,192,505	$ 957,857,015
Noncurrent liabilities	55,717,497	67,994,521	63,771,698	63,952,994	71,956,101
Current liabilities	215,129,588	452,101,465	143,606,465	179,361,400	120,898,099
Deferred credits	36,970,209	21,216,712	20,255,473	1,715,984	1,874,714
Equity	290,126,235	298,260,089	300,125,374	373,465,781	413,279,048
Total liabilities & equity	$ 2,060,552,691	$ 2,205,020,666	$ 2,210,961,487	$ 1,641,688,664	$ 1,565,864,977
STATEMENTS OF REVENUES AND EXPENSES					
Operating Revenues					
Residential	$ 199,071,882	$ 211,964,191	$ 178,129,446	$ 148,343,023	$ 142,542,347
Commercial	243,536,088	238,263,423	198,578,662	159,202,753	141,105,588
Industrial	57,724,174	63,204,524	58,894,805	47,085,945	45,891,368
Governmental	50,785,087	50,287,136	41,905,626	33,669,484	37,766,052
Unbilled revenue - net change	1,115,683	(1,287,056)	25,928,733	3,277,080	629,526
Total retail power revenues	552,232,914	562,432,218	503,437,272	391,578,285	367,934,881
Short-term wholesale power revenues [A, C]	137,650,966	102,082,572	73,899,346	99,168,112	-
Other power-related revenues [A]	34,082,244	20,385,528	44,303,333	11,101,230	-
Other	15,039,174	12,991,925	10,814,019	3,781,072	4,815,884
Total operating revenues	739,005,298	697,892,243	632,453,970	505,628,699	372,750,765
Operating Expenses					
Long-term purchased power [A]	240,505,211	222,943,642	151,213,357	79,304,610	79,984,055
Short-term wholesale power purchases [A, C]	24,232,720	12,440,806	218,781,800	212,402,254	(18,865,574)
Amortization of deferred power costs	100,000,000	100,000,000	-	-	-
Other power expenses	21,139,577	8,147,996	16,143,942	5,504,322	4,508,274
Generation	20,210,903	18,546,296	17,012,159	25,665,927	31,071,778
Transmission [A]	34,511,283	35,352,620	25,820,801	21,726,234	20,960,408
Distribution	39,116,032	37,649,578	38,122,827	34,523,307	37,138,587
Customer service	31,068,350	27,566,006	27,539,641	22,179,214	19,710,363
Conservation	11,014,634	9,514,572	8,887,010	6,972,547	6,794,306
Administrative and general	47,392,441	40,315,378	40,030,657	37,020,250	43,310,839
Taxes	61,606,324	60,173,889	52,565,660	42,860,055	38,661,079
Depreciation	69,270,029	66,485,780	61,538,960	55,498,917	54,022,390
Total operating expenses	700,067,504	639,136,563	657,656,814	543,657,637	317,296,505
Net operating income (loss)	38,937,794	58,755,680	(25,202,844)	(38,028,938)	55,454,260
Gain on sale of Centralia steam plant	-	-	-	29,639,799	-
Other income (expense), net	36,192	357,968	(1,048,013)	(240,039)	(3,907,245)
Investment income	3,813,194	10,110,004	13,275,220	9,753,106	4,140,404
Total operating and other income (loss)	42,787,180	69,223,652	(12,975,637)	1,123,928	55,687,419
Interest Expense					
Interest expense	78,272,394	84,933,182	79,584,722	53,651,607	46,952,066
Amortization of debt expense	3,120,011	2,717,316	1,786,694	5,054,837	5,208,932
Interest charged to construction	(4,337,717)	(3,592,785)	(5,710,936)	(5,553,780)	(4,212,048)
Net interest expense	77,054,688	84,057,713	75,660,480	53,152,664	47,948,950
Fees, grants, and transfers [B]	26,133,654	12,968,776	15,295,710	-	-
Net income (loss)	$ (8,133,854)	$ (1,865,285)	$ (73,340,407)	$ (52,028,736)	$ 7,738,469

[A] Beginning in 2001, wholesale power and power-related sales have been recorded as operating revenues. Prior to 2001, these sales were recorded as offsets to power and transmission expenses. Amounts for 2000 were reclassified to conform to the new presentation. Amounts for years prior to 2000 have not been reclassified.

[B] Fees, grants, and transfers were reported as nonoperating revenues beginning in 2001 due to the adoption of GASB Statement No. 33. Prior to the implementation of this standard, capital fees from private sources were reported as a component of equity as contributions in aid of construction, while grants and transfers were reported as offsets to expenses.

[C] For 2003 and 2002, wholesale power sales and purchases that are bookouts are reported on a net basis due to the implementation of EITF-0311. Amounts for 2002 were reclassified and amounts for years prior to 2002 have not been reclassified.

Note: Certain other 2002 account balances have been reclassified to conform to the 2003 presentation.

INTEREST REQUIREMENTS AND PRINCIPAL REDEMPTION ON LONG-TERM DEBT (Unaudited)

As of December 31, 2003

	Prior Lien Bonds			Subordinate Lien Bonds		Note Payable - City of Seattle	
Years	Principal	Interest	Total	Principal	Interest [B]	Principal	Interest
2004	$ 49,705,000	$ 73,667,837	$ 123,372,837	$ 4,115,000	$1,014,316	$ -	$257,932
2005	52,781,000	71,551,006	124,332,006	4,445,000	945,622	5,158,625	257,931
2006	56,225,000	69,253,098	125,478,098	4,775,000	888,514	-	-
2007	58,945,000	66,524,336	125,469,336	5,305,000	839,458	-	-
2008	62,055,000	63,416,923	125,471,923	5,840,000	786,227	-	-
2009	65,365,000	60,115,897	125,480,897[A]	6,270,000	726,678	-	-
2010	68,845,000	56,633,422	125,478,422	6,705,000	659,452	-	-
2011	64,310,000	53,223,982	117,533,982	7,345,000	601,148	-	-
2012	64,615,000	49,740,857	114,355,857	7,785,000	512,536	-	-
2013	67,410,000	46,150,081	113,560,081	8,425,000	426,392	-	-
2014	67,910,000	42,488,431	110,398,431	8,865,000	337,999	-	-
2015	68,380,000	38,796,188	107,176,188	9,410,000	242,169	-	-
2016	69,110,000	35,036,006	104,146,006	7,755,000	137,824	-	-
2017	69,230,000	31,253,800	100,483,800	2,600,000	90,580	-	-
2018	68,360,000	27,833,611	96,193,611	2,750,000	63,279	-	-
2019	65,395,000	24,163,723	89,558,723	1,300,000	35,419	-	-
2020	63,385,000	20,637,728	84,022,728	1,355,000	21,651	-	-
2021	61,175,000	17,288,662	78,463,662	1,410,000	7,312	-	-
2022	60,055,000	13,986,565	74,041,565	-	-	-	-
2023	59,805,000	10,747,524	70,552,524	-	-	-	-
2024	60,750,000	7,521,031	68,271,031	-	-	-	-
2025	44,480,000	4,434,148	48,914,148	-	-	-	-
2026	38,585,000	2,104,581	40,689,581	-	-	-	-
2027	8,875,000	909,750	9,784,750	-	-		
2028	9,320,000	466,000	9,786,000	-	-	-	-
Totals	$1,425,071,000	$887,945,187	$2,313,016,187	$96,455,000	$8,336,576	$5,158,625	$515,863

[A] Maximum debt service--see Note 6 on page 38.
[B] Based on actual interest rates in effect as of December 31, 2003 ranging from 0.90% to 1.06%.

DEBT SERVICE COVERAGE: Prior Lien Bonds (Unaudited)

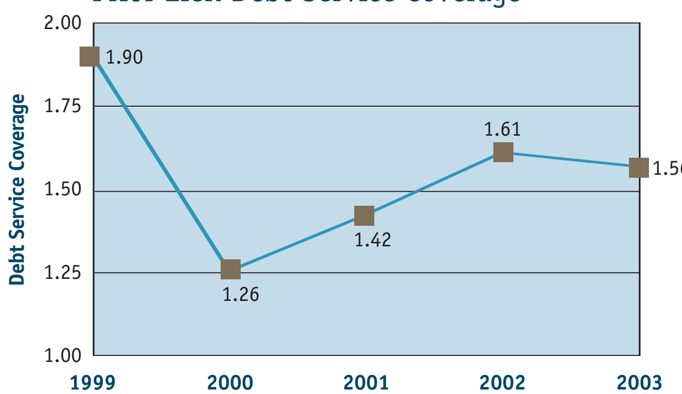
Years ended December 31,

	Revenue Available for Debt Service	Debt Service Requirements	Debt Service Coverage
2003	$164,482,458 [A]	$105,719,316	1.56
2002	177,824,771 [A]	110,664,535	1.61
2001	87,604,015 [B]	61,552,303	1.42
2000	104,629,835	83,205,503	1.26
1999	143,335,963	75,369,637	1.90

[A] Operation and maintenance expenses in 2003 and 2002 include $100 million each year for amortization of a portion of $300 million in power costs deferred in 2001, reducing revenue available for debt service by that amount.

[B] Operation and maintenance expenses in 2001 exclude $300 million in deferred power costs, incurred in 2001, increasing revenue available for debt service by that amount.

Prior Lien Debt Service Coverage



STATEMENT OF LONG-TERM AND SHORT-TERM DEBT (Unaudited)

As of December 31, 2003

Name of Bond	When Due	Interest Rate (%)	Amount Issued	Amount Outstanding 12/31/03	Amount Due Within One Year	Accrued Interest
Debt outstanding at 12-31-03						
PRIOR LIEN BONDS						
Series 1993	2004	5.000	$ 20,215,000	$ 20,215,000	$ 20,215,000	$ 169,384
Series 1994	2004	6.000	3,450,000	3,450,000	3,450,000	103,500
Series 1995	2004	5.000	2,035,000	2,035,000	2,035,000	34,103
Series 1995	2005	4.800	456,000	456,000		7,336
Series 1995	2006-2007	5.000	4,650,000	4,650,000		77,926
Series 1995	2008	5.125	2,515,000	2,515,000		43,201
Series 1995	2009	5.300	2,655,000	2,655,000		47,163
Series 1995	2010	5.400	2,805,000	2,805,000		50,767
Series 1995	2011	5.500	2,970,000	2,970,000		54,749
Series 1995	2012	5.600	3,145,000	3,145,000		59,029
Series 1995	2013-2018	5.625	23,285,000	23,285,000		438,993
Series 1995	2019-2020	5.700	9,815,000	9,815,000		187,510
Series 1996	2004-2008	5.250	5,285,000	5,285,000	950,000	69,745
Series 1996	2009	5.300	1,235,000	1,235,000		16,453
Series 1996	2010	5.400	1,300,000	1,300,000		17,646
Series 1996	2011-2013	5.500	4,365,000	4,365,000		60,347
Series 1996	2014-2021	5.625	16,045,000	16,045,000		226,865
Series 1997	2004-2018	5.000	20,495,000	20,495,000	970,000	512,375
Series 1997	2019-2022	5.125	8,575,000	8,575,000		219,734
Series 1998	2004	4.500	740,000	740,000	740,000	16,650
Series 1998	2005-2008	4.750	18,990,000	18,990,000		451,012
Series 1998	2009-2020	5.000	82,390,000	82,390,000		2,059,750
Series 1998	2004-2019	4.750	59,545,000	59,545,000	2,615,000	239,563
Series 1998	2021	4.875	11,250,000	11,250,000		46,452
Series 1998	2024	5.000	19,205,000	19,205,000		81,333
Series 1999	2006-2007	5.000	6,250,000	6,250,000		78,552
Series 1999	2008-2009	5.750	13,500,000	13,500,000		195,123
Series 1999	2010	5.875	2,500,000	2,500,000		36,919
Series 1999	2011-2024	6.000	135,750,000	135,750,000		2,047,377
Series 2000	2006	5.000	2,875,000	2,875,000		12,176
Series 2000	2007	4.500	3,015,000	3,015,000		11,492
Series 2000	2008	5.250	3,150,000	3,150,000		14,007
Series 2000	2009-2011	5.500	10,505,000	10,505,000		48,937
Series 2000	2012-2018	5.625	32,325,000	32,325,000		154,007
Series 2000	2019	5.250	5,715,000	5,715,000		25,413
Series 2000	2020	5.300	6,015,000	6,015,000		27,002
Series 2000	2021	5.250	6,330,000	6,330,000		28,148
Series 2000	2022-2025	5.400	28,900,000	28,900,000		132,182

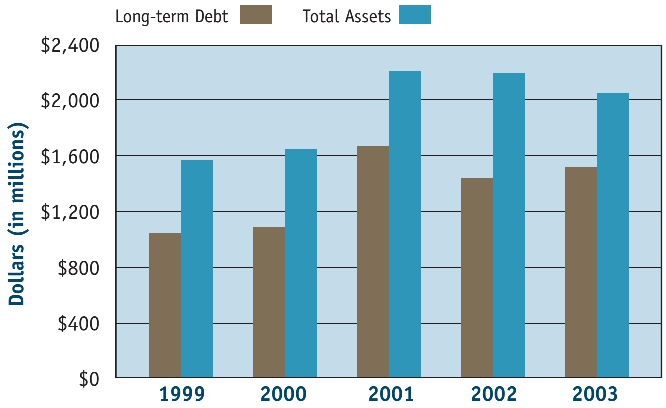
Continued on next page.

Name of Bond	When Due	Interest Rate (%)	Amount Issued	Amount Outstanding 12/31/03	Amount Due Within One Year	Accrued Interest
Series 2001	2004-2007	5.250	23,140,000	23,140,000	3,735,000	407,175
Series 2001	2008-2010	5.500	41,580,000	41,580,000		766,488
Series 2001	2010-2011	5.250	41,990,000	41,990,000		738,863
Series 2001	2012-2019	5.500	215,175,000	215,175,000		3,966,550
Series 2001	2020	5.000	22,165,000	22,165,000		371,446
Series 2001	2021-2026	5.125	159,650,000	159,650,000		2,742,340
Series 2002	2004-2013	4.000	48,985,000	48,985,000	5,080,000	165,960
Series 2002	2008	4.500	10,230,000	10,230,000		38,991
Series 2002	2009	4.375	10,725,000	10,725,000		39,743
Series 2002	2010	4.500	10,675,000	10,675,000		40,688
Series 2002	2014	4.125	4,660,000	4,660,000		16,281
Series 2003	2004	6.000	9,915,000	9,915,000	9,915,000	99,695
Series 2003	2005	4.000	24,525,000	24,525,000		164,398
Series 2003	2006-2013	5.000	95,975,000	95,975,000		804,186
Series 2003	2014-2020	5.250	58,190,000	58,190,000		511,960
Series 2003	2021-2028	5.000	63,245,000	63,245,000		529,938
Total Prior Lien Bonds			$ 1,425,071,000	$1,425,071,000	$ 49,705,000	$ 19,507,623
SUBORDINATE LIEN BONDS						
Series 1990	2003-2015	0.750-1.200 [A]	$ 18,700,000	$ 18,700,000	$ 1,100,000	$ 33,080
Series 1991	2003-2016	0.640-1.300 [A]	41,500,000	41,500,000	1,400,000	90,400
Series 1993	2003-2018	0.640-1.230 [A]	17,800,000	17,800,000	900,000	12,401
Series 1996	2003-2021	0.600-1.300 [A]	18,455,000	18,455,000	715,000	13,409
Total Subordinate Bonds			$ 96,455,000	$ 96,455,000	$ 4,115,000	$ 149,290
CITY OF SEATTLE						
Note Payable - Long-Term	2005	5.000	$ 5,158,625	$ 5,158,625	$ -	$ 11,667
Short-Term Borrowings	2004	Variable	70,000,000	70,000,000	70,000,000	128,966
Total - City of Seattle			$ 75,158,625	$ 75,158,625	$ 70,000,000	$ 140,633
Total			$ 1,596,684,625	$ 1,596,684,625	$ 123,820,000	$ 19,797,546

[A] Range of adjustable rates in effect during 2003.

(Concluded)

Long-Term Debt and Total Assets

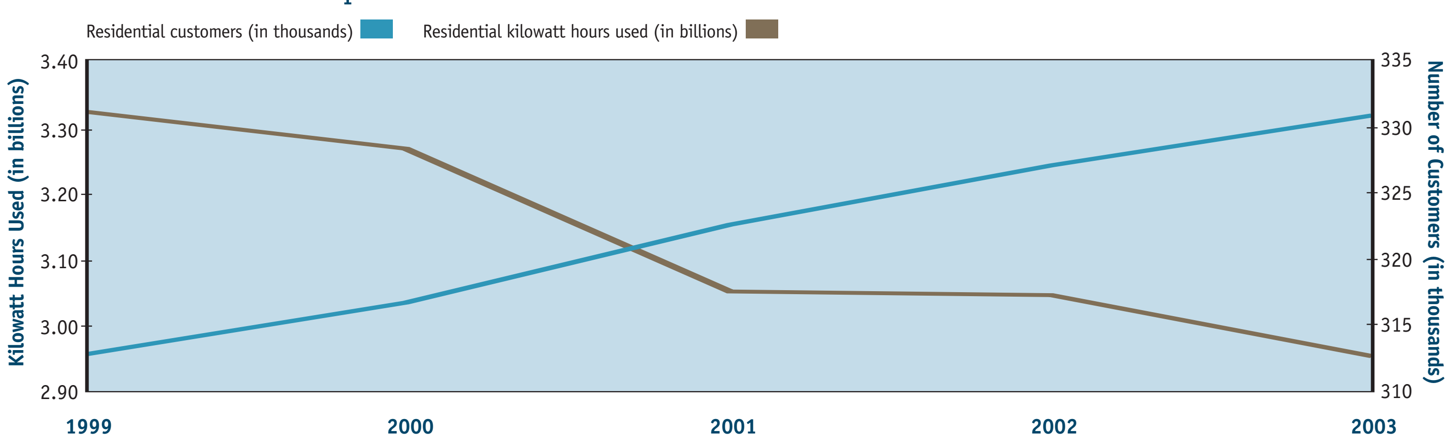


CUSTOMER STATISTICS (Unaudited)

Years ended December 31,		2003		2002		2001		2000		1999
AVERAGE NUMBER OF CUSTOMERS										
Residential		330,979		327,127		322,707		316,758		312,849
Commercial		32,380		31,418		30,934		30,839		30,568
Industrial		260		263		259		276		279
Governmental		1,826		1,824		1,776		1,686		1,817
Total		365,445		360,632		355,676		349,559		345,513
KILOWATT HOURS (IN 000'S)										
Residential	33%	2,952,615	34%	3,045,768	34%	3,050,900	34%	3,267,710	35%	3,322,835
Commercial	44%	3,945,058	43%	3,872,749	42%	3,829,360	41%	3,932,043	40%	3,753,167
Out of service area (commercial) [A]	-	-	-	-	-	15,956	1%	96,399	1%	89,907
Industrial	13%	1,166,967	13%	1,165,532	14%	1,237,424	14%	1,352,457	14%	1,349,809
Governmental	10%	841,304	10%	839,081	10%	858,111	10%	908,283	10%	972,081
Total	100%	8,905,944	100%	8,923,130	100%	8,991,751	100%	9,556,892	100%	9,487,799
AVERAGE ANNUAL REVENUE PER CUSTOMER (in service area)										
Residential		$ 602		$ 643		$ 582		$ 476		$ 457
Commercial		$ 7,512		$ 7,638		$ 6,662		$ 4,932		$ 4,569
Industrial		$ 223,177		$ 234,189		$ 243,410		$ 171,125		$ 166,100
Governmental		$ 28,247		$ 27,772		$ 24,751		$ 19,920		$ 20,422

[A] Sales to California terminated March 31, 2001.

Residential Consumption



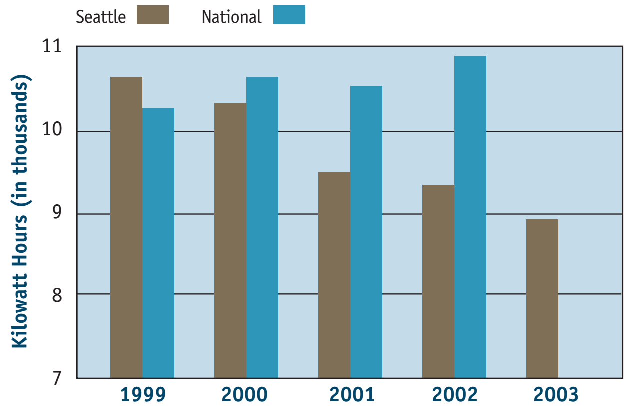
CUSTOMER STATISTICS (Unaudited)

Years ended December 31,		2003	2002	2001	2000	1999
AVERAGE ANNUAL CONSUMPTION PER CUSTOMER (kWh) [A]						
Residential	- Seattle	8,921	9,311	9,454	10,316	10,621
	- National	n/a	10,884	10,524	10,623	10,237
Commercial	- Seattle	121,836	123,265	124,307	130,628	122,781
	- National	n/a	73,068	72,900	71,640	68,858
Industrial	- Seattle	4,488,335	4,431,681	4,777,699	4,900,207	4,838,026
	- National	n/a	1,633,020	1,678,776	1,909,814	1,930,929
Governmental	- Seattle	460,736	460,022	483,171	538,721	534,992
	- National	n/a	n/a	n/a	n/a	106,614
AVERAGE RATE PER KILOWATT HOUR (CENTS) [A]						
Residential	- Seattle	6.75	6.90	6.16	4.61	4.30
	- National	8.71	8.46	8.62	8.24	8.16
Commercial	- Seattle	6.17	6.20	5.36	3.78	3.72
	- National	8.13	7.86	7.93	7.43	7.26
Industrial	- Seattle	4.97	5.28	5.09	3.49	3.42
	- National	4.95	4.88	5.04	4.64	4.43
Governmental	- Seattle	6.13	6.04	5.12	3.70	3.83
	- National	6.95	6.73	7.03	6.56	6.35
Total	- Seattle	6.20	6.30	5.57	4.01	3.89
	- National	7.40	7.21	7.32	6.81	6.64

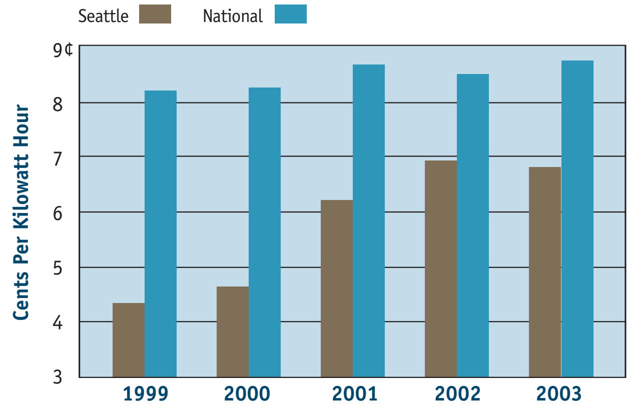
[A] Source of national data: Department of Energy (2003 estimated, 2002 revised; 2003 consumption data is not available).

NOTE: The latest rate adjustment is effective April 1, 2004. Rates are set by the Seattle City Council. Notice of public hearings may be obtained on request to The Office of the City Clerk, City Hall, 600-4th Avenue, Floor Three, Seattle WA 98104. Additional information about public hearings can be found on the Web at http://www.cityofseattle.net/council/hearings_forums.htm. Additional information about Council meetings can be found on the Web at http://www.seattle.gov/council/meetings.htm.

Average Annual Residential Consumption



Average Residential Rates

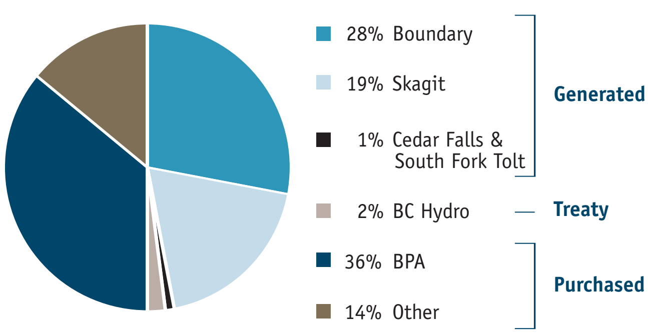


POWER (Unaudited)

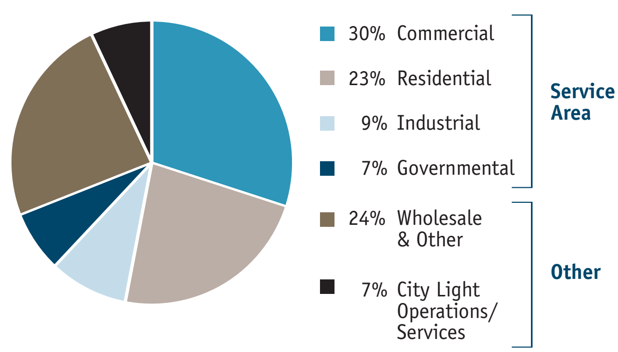
Years ended December 31,	2003	2002	2001	2000	1999
POWER COSTS					
Hydraulic generation [A]	$ 31,035,885	$ 28,983,385	$ 27,425,917	$ 28,288,083	$ 26,746,081
Steam generation [A, B]	-	-	-	7,521,097	14,664,491
Long-term purchased power [C]	240,505,211	222,943,642	151,213,357	79,304,610	79,984,055
Wholesale power purchases [D, I]	38,121,479	14,306,336	518,781,800	212,402,254	34,295,550
Power costs amortized (deferred) [E]	100,000,000	100,000,000	(300,000,000)	-	-
Owned transmission [A]	7,358,577	7,171,946	6,768,055	5,775,106	6,504,089
Wheeling expenses	30,102,277	31,065,472	21,906,286	18,431,914	16,864,661
Other power expenses	7,250,818	6,282,466	16,143,942	5,504,322	4,508,274
Total power costs	454,374,247	410,753,247	442,239,357	357,227,386	183,567,201
Less short-term wholesale power sales [D]	(137,650,966)	(102,082,572)	(73,899,346)	(99,168,112)	(53,161,124)
Less other power-related revenues [F]	(34,082,244)	(20,385,528)	(44,303,333)	(11,101,230)	-
Net power costs [H]	$ 282,641,037	$ 288,285,147	$ 324,036,678	$ 246,958,044	$ 130,406,077
POWER STATISTICS (MWh)					
Hydraulic generation [D]	6,098,753	6,891,659	3,941,388	6,405,929	7,764,312
Steam generation [B]	-	-	-	277,103	689,802
Long-term purchased power [C]	6,985,518	6,519,770	4,307,958	3,418,245	3,213,813
Wholesale power purchases [D]	1,210,699	898,613	2,411,210	2,459,825	1,159,875
Wholesale power sales [D]	(4,262,041)	(4,647,945)	(468,827)	(2,230,670)	(2,672,264)
Other [G]	(1,126,985)	(738,967)	(1,199,978)	(773,540)	(667,739)
Total power delivered to retail customers	8,905,944	8,923,130	8,991,751	9,556,892	9,487,799
Net power cost per MWh delivered [H]	$ 31.74	$ 32.31	$ 36.04	$ 25.84	$ 13.74

[A] Including depreciation.
[B] The Centralia Steam Plant was sold in May 2000.
[C] Effective 2000, long-term purchased power includes energy received under seasonal exchange contracts, valued at the blended weighted average cost of power excluding depreciation and transmission.
[D] The level of generation (and consequently the amount of power purchased and sold on the wholesale market) can fluctuate widely from year to year depending upon water conditions in the Northwest region. The Northwest experienced a severe drought in 2001. During 2003, 2002 and 2000, the region experienced lower than average water conditions. Conditions were favorable in 1999.
[E] Wholesale power purchase costs in the amount of $300,000,000 incurred in 2001 were deferred to future years. In 2003 and 2002, $100 million of the deferred costs were amortized each year.
[F] Beginning in 2000, other power-related revenues include energy delivered under seasonal exchange contracts, valued at the blended weighted average cost of power excluding depreciation and transmission.
[G] "Other" includes self-consumed energy, system losses and miscellaneous power transactions. In 1999, "other" also includes seasonal power exchanges delivered and received. Effective 2000, seasonal exchange power delivered is included in "other", while seasonal exchange power received is included in long-term purchased power.
[H] If power costs had not been deferred in 2001, the net power cost per MWh delivered would have been $20.51 in 2003, $21.10 in 2002, and $69.41 in 2001.
[I] For 2003 and 2002, bookout purchases are excluded from wholesale power purchases and are reported on a net basis in wholesale power sales due to the implementation of EITF-0311. Amounts for years prior to 2002 have not been reclassified.

Sources of Power (in percent of MWh)



Uses of Power (in percent of MWh)



CHANGES IN OWNED TOTAL GENERATING INSTALLED CAPABILITY (Unaudited)

Year	Plant	KW Added	Peaking Capability Total KW
1904-09	Cedar Falls Hydro Units 1, 2, 3 & 4	10,400	10,400
1912	Lake Union Hydro Unit 10	1,500	11,900
1914-21	Lake Union Steam Units 11, 12 & 13	40,000	51,900
1921	Newhalem Hydro Unit 20	2,300	54,200
1921	Cedar Falls Hydro Unit 5	15,000	69,200
1924-29	Gorge Hydro Units 21, 22 & 23	60,000	129,200
1929	Cedar Falls Hydro Unit 6	15,000	144,200
1932	Cedar Falls Hydro Units 1, 2, 3 & 4	(10,400)[A]	133,800
1932	Lake Union Hydro Unit 10	(1,500)[A]	132,300
1936-37	Diablo Hydro Units 31, 32, 35 & 36	132,000	264,300
1951	Georgetown Steam Units 1, 2 & 3	21,000	285,300
1951	Gorge Hydro Unit 24	48,000	333,300
1952-56	Ross Hydro Units 41, 42, 43 & 44	450,000	783,300
1958	Diablo Plant Modernization	27,000	810,300
1961	Gorge Hydro, High Dam	67,000	877,300
1967	Georgetown Plant, performance test gain	2,000	879,300
1967	Boundary Hydro Units 51, 52, 53 & 54	652,000	1,531,300
1972	Centralia Units 1 & 2	102,400	1,633,700
1980	Georgetown Steam Units 1, 2, & 3	(23,000)[A]	1,610,700
1986	Boundary Hydro Units 55 & 56	399,000	2,009,700
1987	Lake Union Steam Units 11, 12 & 13	(40,000)[A]	1,969,700
1989-92	Gorge Units 21, 22, & 23, new runners	4,600	1,974,300
1993	Centralia Transmission Upgrade	5,000	1,979,300
1995	South Fork Tolt	16,800	1,996,100
2000	Centralia Units 1 & 2	(107,400)[B]	1,888,700

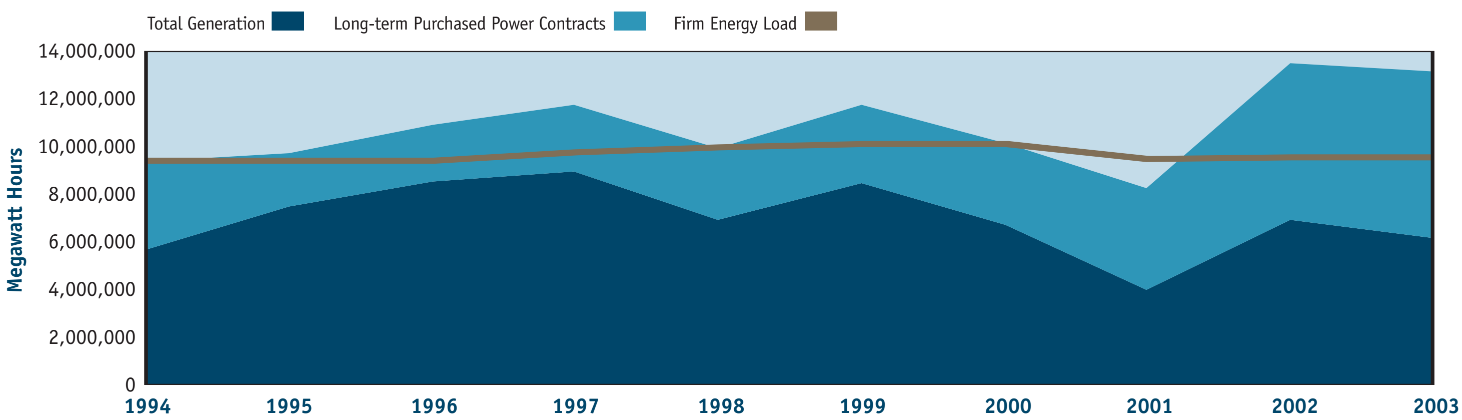
[A] Retirement of units (decrease in total capability).
[B] The Centralia Steam Plant was sold in May 2000.

SYSTEM REQUIREMENTS (Unaudited)

Year	Kilowatts Average Load	Kilowatts Peak Load[C]
1950	154,030	312,000
1955	381,517	733,000
1960	512,787	889,000
1965	635,275	1,138,000
1970	806,813	1,383,000
1975	848,805	1,429,387
1980	963,686	1,771,550
1985	1,025,898	1,806,341
1986	996,648	1,699,434
1987	987,070	1,724,726
1988	1,022,442	1,731,518
1989	1,059,272	1,979,528
1990	1,088,077	2,059,566
1991	1,065,987	1,815,164
1992	1,048,055	1,743,975
1993	1,082,616	1,875,287
1994	1,074,852	1,819,323
1995	1,072,692	1,748,657
1996	1,110,133	1,950,667
1997	1,111,035	1,816,152
1998	1,120,178	1,928,854
1999	1,142,382	1,729,933
2000	1,142,383	1,769,440
2001	1,082,068	1,661,842
2002	1,087,519	1,689,666
2003	1,087,901	1,645,998

[C] One-hour peak.

Total Generation and Long-Term Purchased Power Contracts vs. Firm Load

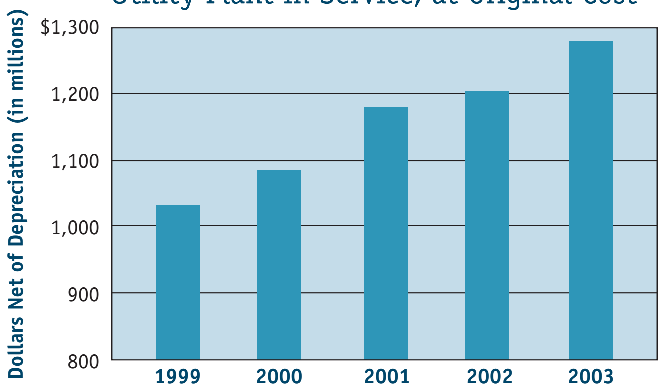


UTILITY PLANT, AT ORIGINAL COST (Unaudited)

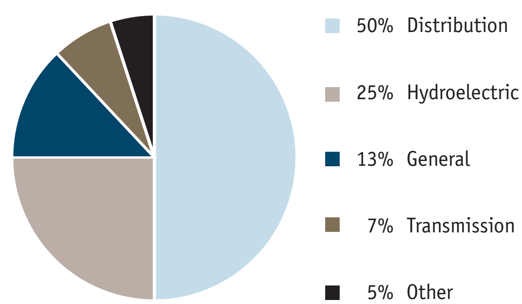
Years ended December 31,	2003	2002	2001	2000	1999
Steam plant* [A]	$ -	$ -	$ -	$ -	$ 28,620,025
Hydroelectric plant*	581,316,129	548,545,811	542,541,330	531,705,122	507,902,539
Transmission plant*	149,004,899	142,863,829	140,352,499	135,787,595	130,371,827
Distribution plant*	1,151,824,817	1,075,113,770	1,022,638,123	953,429,070	892,578,913
General plant*	310,305,883	298,815,388	280,149,800	218,149,068	203,660,796
Total electric plant in service	2,192,451,728	2,065,338,798	1,985,681,752	1,839,070,855	1,763,134,100
Accumulated depreciation	(914,978,513)	(862,964,940)	(808,183,648)	(756,498,166)	(731,545,437)
Total plant in service, net of depreciation	1,277,473,215	1,202,373,858	1,177,498,104	1,082,572,689	1,031,588,663
Nonoperating properties, net of depreciation	11,860,650	7,703,571	7,216,228	6,613,263	6,366,276
Utility plant, net of depreciation	1,289,333,865	1,210,077,429	1,184,714,332	1,089,185,952	1,037,954,939
Construction work-in-progress	101,523,497	135,358,152	115,321,307	152,981,465	118,281,967
Net utility plant	$ 1,390,857,362	$ 1,345,435,582	$ 1,300,035,639	$ 1,242,167,417	$ 1,156,236,906

[A] The Centralia steam plant was sold in May 2000.
* Including land.

Utility Plant in Service, at Original Cost



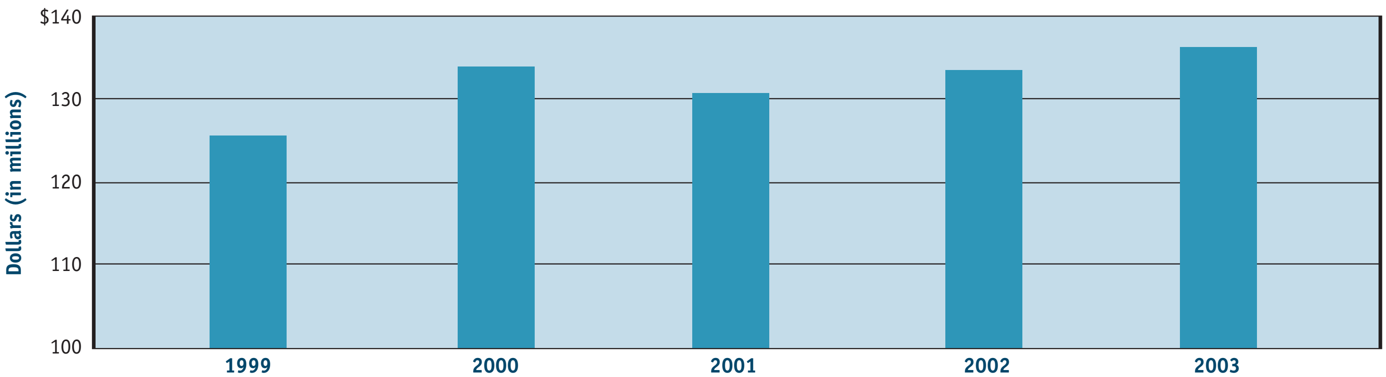
2003 Utility Plant, at Original Cost



PAYROLL AND EMPLOYEE BENEFITS (Unaudited)

Years ended December 31,	2003	2002	2001	2000	1999
Full-time equivalent positions	1,625	1,618	1,628	1,647	1,627
Straight time	$ 80,138,335	$ 77,516,850	$ 75,801,957	$ 74,286,122	$ 71,440,967
Overtime	10,625,974	9,744,907	9,431,112	16,287,675	13,978,470
Vacation and other	16,486,348	16,035,490	16,635,444	15,680,918	15,474,009
Total payroll	107,250,657	103,297,247	101,868,513	106,254,715	100,893,446
Employee benefits	28,657,452	29,956,272	28,306,941	27,336,784	24,418,514
Total payroll and employee benefits	$ 135,908,109	$ 133,253,519	$ 130,175,454	$ 133,591,499	$ 125,311,960
Percentage of employee benefits (including vacation) to straight time	56.3%	59.3%	59.3%	57.9%	55.8%

Payroll and Employee Benefits



TAXES AND CONTRIBUTIONS TO THE COST OF GOVERNMENT (Unaudited)

Years ended December 31,	2003	2002	2001	2000	1999
TAXES					
City of Seattle occupation tax	$ 33,607,729	$ 33,913,510	$ 30,648,910	$ 24,002,685	$ 21,791,151
State public utility and business taxes	23,079,374	22,035,382	19,555,852	15,631,467	14,205,768
Local franchise and other special taxes [A]	2,706,490	2,079,791	295,474	1,161,177	676,575
Contract payments for government services	2,212,731	2,145,206	2,065,424	2,064,726	1,987,585
Total taxes as shown in statement of revenues and expenses	61,606,324	60,173,889	52,565,660	42,860,055	38,661,079
Taxes/licenses charged to accounts other than taxes	10,323,591	9,801,000	8,291,537	9,012,216	8,874,311
Other contributions to the cost of government	4,586,025	4,067,380	3,582,034	4,422,403	3,524,019
Total miscellaneous taxes	14,909,616	13,868,380	11,873,571	13,434,619	12,398,330
Total taxes and contributions	$ 76,515,940	$ 74,042,269	$ 64,439,231	$ 56,294,674	$ 51,059,409

Note: Electric rates include all taxes and contributions. The State Public Utility Tax for retail electric power sales was 3.873%. The City of Seattle Occupation Utility Tax was 6% for in-state retail electric power sales and 5% for out-of-state retail electric power sales.

[A] 2001 includes a refund of $1,224,200 previously paid to the Federal Government as arbitrage rebate payments related to the Municipal Light & Power Revenue Bonds, 1986 and 1988.

PUBLIC PURPOSE EXPENDITURES (Unaudited)

Years ended December 31,	2003	2002	2001	2000	1999
CONSERVATION [A]					
Non-programmatic conservation expenses [B]	$ 1,299,856	$ 1,273,584	$ 1,806,864	$ 1,903,001	$ 2,539,336
Conservation programs [C]					
Non-low income	15,568,382	15,753,515	23,184,059	13,840,045	16,137,211
Low income	1,962,478	2,582,212	1,673,698	1,863,892	1,820,369
External conservation program funding					
Bonneville Power Administration					
Non-low income	-	(17,898)	(4,273)	-	(1,680,060)
Low income	-	-	-	-	-
Customer obligation repayments [D]	(1,008,724)	(1,465,272)	(1,595,954)	(1,468,189)	(2,306,792)
LOW-INCOME ENERGY ASSISTANCE [E]	6,886,535	8,317,273	4,374,503	3,785,996	3,905,699
NON-HYDRO RENEWABLE RESOURCES [F]	12,111,616	7,475,003	381,279	238,015	241,715
Net public purpose spending	$ 36,820,143	$ 33,918,417	$ 29,820,176	$ 20,162,760	$ 20,657,478
Revenue from electric sales	$ 552,232,914	$ 562,432,218	$ 503,437,272	$ 391,578,285	$ 367,934,881
Percent public purpose spending	6.7%	6.0%	5.9%	5.1%	5.6%
Energy savings in year (MWh) [G]	885,492	849,995	788,191	710,560	679,124

Note: Certain prior year amounts have been revised.

[A] Non-programmatic conservation is funded from current revenues. Conservation programs are financed by either debt or current revenues. Conservation expenditures are deferred and amortized over a 20-year period in accordance with City Council-passed resolutions.

[B] Non-programmatic expenditures include support of energy codes and activities that encourage utility customers to adopt new technologies on their own, manufacturers to produce more efficient technologies, program planning, evaluation, data processing, and general administration. These expenses are not associated with measured energy savings.

[C] Non-low income programmatic conservation includes expenditures for program measures, customer incentives, field staff salaries, and direct program administration. Low-income programmatic conservation includes these types of expenditures for the Department's Low-Income Electric and Low-Income Multifamily Programs.

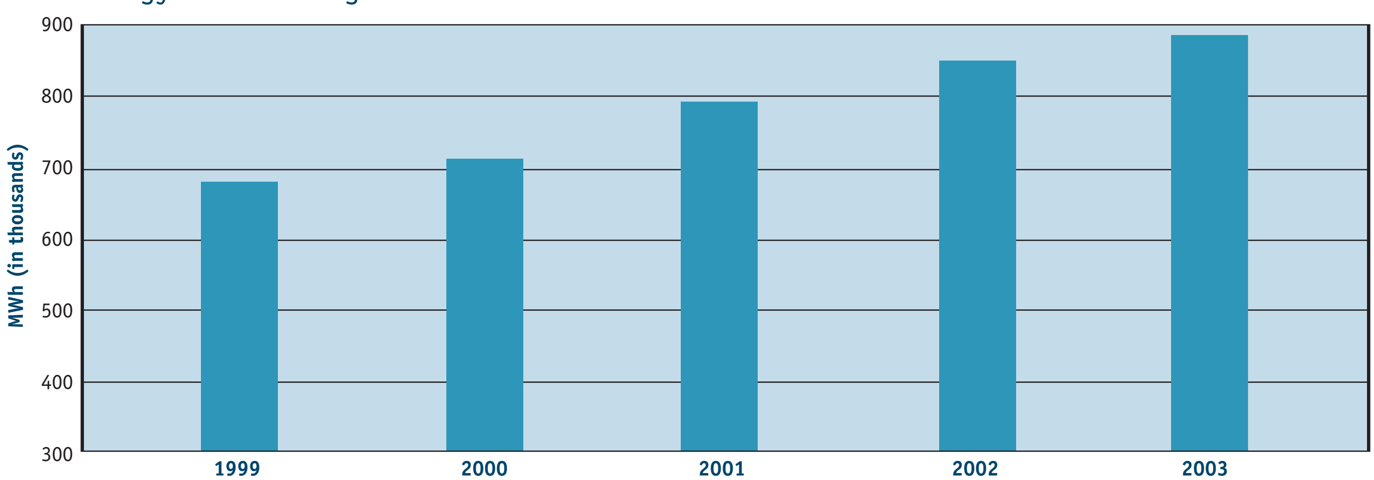
[D] Customer obligations repaid in each year include payments on outstanding five-year or ten-year loans, plus repayments in the first year after project completion for utility-financed measures.

[E] Low-income assistance includes rate discounts and other programs that provide assistance to low income customers.

[F] Non-hydro renewable resources include co-generation from the West Point Sewage Treatment plant and power generated from the Stateline Wind Project. Both of these resources are funded from current revenues. In 2003, the Department purchased from the West Point plant approximately 14,333 MWh of energy generated by three reciprocating engines using methane gas from the treatment plant. Total electrical output was purchased under a power purchase contract executed with Metro in 1983, which expired September 2003. The Department purchased 140,850 MWh from the Stateline Wind project in 2002 and 220,317 MWh in 2003; of which 106,493 MWh were delivered in 2002 and 216,290 MWh in 2003.

[G] Electricity savings in each year are from cumulative conservation program participants, for completed projects with unexpired measure lifetimes.

Energy Saved Through Conservation



Seattle City Light

EXECUTIVE TEAM

Jorge Carrasco
Superintendent

Dana Backiel
Deputy Superintendent – Generation Branch
Generation Engineering
Generation Plant Operations
Generation Program Management
Boundary Capital Improvement Project
Skagit Capital Improvement Project

Mike Sinowitz
Deputy Superintendent – Power Management Branch
Power Marketing
Operations Planning
Automated Systems

Hardev Juj
Deputy Superintendent (acting) – Distribution Branch
Systems Operations
North Electric Service
South Electric Service
Central Electric Service
Power Stations
Distribution Program Management
Transmission - Distribution Planning
Apprenticeship Office

Joan Walters
Deputy Superintendent – Customer Services Branch
Account Executives
Account Services
Energy Management Services
Hearing Officer

Jim Ritch
Deputy Superintendent – Finance and Administration Branch
Finance
Facilities Management
Information Technology

Nancy Glaser
Director of Strategic Planning and Environment & Safety

Beatrice Hughes
Director of Human Resources (acting)

Bob Royer
Director of Communications and Public Affairs

ELECTED OFFICIALS

Mayor
Greg Nickels

Seattle City Council
Jan Drago, Council President
Chair: Government Affairs and Labor Committee

Jim Compton
Chair: Utilities and Technology Committee

Richard Conlin
Chair: Transportation Committee

David Della
Chair: Parks, Neighborhoods, and Education Committee

Jean Godden
Chair: Energy and Environmental Policy Committee

Nick Licata
Chair: Public Safety, Civil Rights, and Arts Committee

Richard McIver
Chair: Finance and Budget Committee

Tom Rasmussen
Chair: Housing, Human Services, and Health Committee

Peter Steinbrueck
Chair: Urban Development and Planning Committee

City Attorney
Thomas A. Carr

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At least 20% of the wood fiber used in this guide comes from well managed forests independently certified in accordance with the rules of the Forest Stewardship Council A.C. The remainder is post-consumer recycled fiber.

In April 2001, the Office of Arts & Cultural Affairs commissioned Lyn McCracken as the artist-in-residence for Seattle City Light to capture the utility's facilities, people, and values.

Her photos became part of the Portable Works Collection, a rotating collection of approximately 2,400 artworks funded by the City's One Percent for Art ordinance.

Seattle City Light

Executive Office
700 Fifth Avenue, Suite 3300
P.O. Box 34023
Seattle, Washington 98124-4023
www.seattle.gov/light
206.684.3200