The Order required hearings in one case to determine whether refunds should be ordered for transactions in the California markets operated by the California Independent System Operator and the California Power Exchange and in a second case to determine whether refunds should be ordered for transactions in the Pacific Northwest markets. Hearings have been completed in both cases. FERC has denied relief to the City in the California case and relief to all plaintiffs in the Pacific Northwest case. Both decisions have been appealed to the Ninth Circuit.

The City also is involved in other legal actions before FERC relating to the failure of the California Independent System Operator to pay the Department for power deliveries in the fall of 2000 and the bankruptcy filings of the California Power Exchange, Pacific Gas and Electric Company and Enron. Finally, the City has intervened in a FERC investigation of companies that may have cooperated with Enron in transactions designed to adversely affect the California and West Coast markets. The outcome of all these actions remains uncertain.

None of these actions is expected to materially adversely affect the financial condition of the Department.

POWER RESOURCES

Overview of Resources

The Department typically meets a major portion of its energy requirements from its own power resources. These include four large and three small hydroelectric facilities that, under average water conditions, generate about 7,000,000 MWh of energy, about 46 percent of the energy available to the Department from its owned and contracted resources. Output from the Department's hydroelectric plants can vary significantly from year to year due to the variability of water conditions. In calendar year 1999, when water conditions were exceptionally good, hydroelectric output totaled 7,778,884 MWh. Under the drought conditions of calendar year 2001, hydroelectric production fell to 3,941,388 MWh. Water conditions in 2003 were again below normal, and hydroelectric generation amounted to 6,112,468 MWh, or 42.8 percent of the total energy available to the Department in that year.

The remainder of the Department's energy requirements are supplied through long-term purchased power contracts and short-term purchases of power in the wholesale market. Purchases of energy from Bonneville under the power sales contract effective October 1, 2001, provided 33.0 percent of available energy in 2003. The remaining 24.2 percent of energy used by the Department in 2003 was provided through long-term contracts with other power providers (15.7 percent) and through short-term purchases in the wholesale power market (8.5 percent). The average cost of energy available to the Department in 2003 from all sources was $14.10 per MWh, excluding transmission and depreciation.

Under the Pacific Northwest Coordination Agreement (the "Coordination Agreement"), the Department and 15 other public and investor-owned utilities in the Northwest have agreed to coordinate the operation of their power generation systems to maximize the firm capability and reliability of the coordinated system. The Coordination Agreement went into effect in 1965 and will terminate on September 24, 2024. Under the terms of the Coordination Agreement, the firm capability of the generating resources of the parties to the agreement is calculated with reference to a critical period, which is defined as that multi-month period of adverse streamflows in the historical record during which the amount of firm load that could be served by the firm resources of the parties to the Coordination Agreement was at a minimum. Water conditions would be expected to be better than those of the critical period about 95 percent of the time.

The table below provides an overview of the Department's power resources.

OWNED AND CONTRACTED POWER RESOURCES
(UNAUDITED)

	One-Hour Peak Capability (MW)	Energy Available Under Critical Water Conditions (MWh) [1]	Energy Available under Average Water Conditions (MWh) [2]	Year FERC License Expires
Department-Owned Resources				
Boundary	1,055	2,985,408	3,906,516	2011
Gorge	177	864,612	977,653	2025
Diablo	159	733,212	758,683	2025
Ross	360	657,000	776,463	2025
Newhalem	2	13,613	13,613	2027
Cedar Falls [3]	30	47,304	102,554	N/A
South Fork Tolt	17	57,365	69,784	2028
Contract Resources				
Bonneville	1,161 [4]	4,185,022	4,609,403	N/A
Box Canyon	12	45,783	45,783	2005
Priest Rapids	68	277,945	329,110	2005
CSPE	21	0	0	N/A
GCPHA	64 [5]	220,262	220,262	2030/2031
High Ross	298 [6]	310,246	310,246	N/A
Lucky Peak	113	249,082	302,490	2030
Metro Cogeneration	1	0	0	N/A
Klamath Falls	100	840,050	840,050	2006
State Line Wind Project	175	455,520	455,520	N/A

(1) Critical water conditions represent the lowest sequence of streamflows experienced in the Northwest region over a historical period of record (1929-2003). The firm energy capability of hydroelectric resources is the amount of energy that would be produced under critical water conditions. Actual water conditions would be expected to be better than critical water conditions about 95 percent of the time.

(2) Figures in this column represent the average amount of energy that would be produced over all of the water conditions in the period of record (1929-2003).

(3) The Cedar Falls Hydroelectric Plant is not subject to FERC licensing requirements.

(4) Approximate. Through purchase of the Slice product, the Department is entitled to 4.6676 percent of the actual output of the Federal System (as defined below under "Purchased Power Arrangements—The Bonneville Power Administration"). The Department is also entitled to purchase 137.8 average MW of Block power (as defined below under "Purchased Power Arrangements—Bonneville Power Administration") from Bonneville in 2004.

(5) The Department's 50 percent share of installed capacity.

(6) The Department's contract with the Province of British Columbia provides capacity from November through March in an amount equal to 532 MW minus the actual capability of the Ross Plant.

Source: Seattle City Light, Finance Division

Resource Acquisitions

In 1996 the Department completed a Strategic Resources Assessment ("SRA") in which it recommended a strategy of reliance on purchases of power in the wholesale market to fill the gap between loads and resources in the near term. In 2000, the Department published an update to the SRA which recommended that the Department pursue a number of alternative power sources and demand-side management options to meet its load requirements beyond 2000. Specifically, the SRA update recommended that the Department maximize its purchases of Bonneville power under a new power sales contract that was to take effect on October 1, 2001; purchase as much Bonneville power as possible in the form of the Slice-of-the-System product (the "Slice") (see "Purchased Power Arrangements—The Bonneville Power Administration"); pursue a contract to purchase 100 MW of power from the Klamath Falls Cogeneration Project to replace power previously supplied by the Centralia Steam Plant (see "Purchased Power Arrangements—Klamath Falls Cogeneration Project"); increase the level of conservation savings to be acquired through 2010 (see "Conservation"); and acquire an estimated 100 average MW of new non-hydro renewable resources (see "Purchased Power Arrangements—Wind Generation"). The City Council approved the recommendations of the 2000 SRA update, and the Department has acquired the recommended resources. The contract for the purchase of power from the Klamath Falls Project expires in July 2006. In 2005, the Department will initiate an integrated resource planning process. The Integrated Resources Plan, which is expected to be completed in 2006, will recommend a resource strategy for the following ten years.

Resource Capabilities and Costs

The following tables show the availability and cost of the Department's resources from 1999 through 2003. In 2000 and 2001, drought conditions in the Northwest resulted in low output from the Department's hydroelectric resources and a high level of purchases from the wholesale power market to fill the resulting energy deficit. See "Recent Developments Affecting the Department." The acquisition of additional power resources over the 2001-2003 period under the Department's resource acquisition plan, together with a reduction in retail load in 2001, provided the Department with substantial amounts of surplus power in 2002 and 2003, even though streamflows in those years were lower than normal..

ENERGY RESOURCES
(MWh) (UNAUDITED)

	1999	2000	2001	2002	2003
Department-Owned Generation					
Boundary	4,465,874	3,809,267	2,339,590	3,971,940	3,589,057
Gorge	1,186,500	959,800	616,754	1,025,291	930,783
Diablo	1,022,509	814,712	477,635	900,255	744,016
Ross	962,487	741,637	392,922	837,204	727,698
Cedar Falls/Newhalem	71,019	53,780	74,430	89,422	71,914
Centralia (1)	689,802	277,103	0	0	0
South Fork Tolt	70,495	44,090	40,057	78,205	49,000
Subtotal	8,468,686	6,700,389	3,941,388	6,902,317	6,112,468
Energy Purchases					
Bonneville (2)	1,582,163	1,701,674	2,391,518	4,659,586	4,713,124
Box Canyon	70,759	57,746	42,663	43,410	47,452
Priest Rapids	412,482	363,740	262,188	326,522	310,716
CSPE	141,117	106,603	102,037	99,348	26,350
GCPHA	250,663	238,987	271,009	248,266	235,496
High Ross	308,353	296,828	307,738	297,123	315,246
Lucky Peak	426,152	340,825	188,403	288,848	292,348
Metro Cogeneration	7,553	7,419	11,915	14,539	14,333
Klamath Falls	0	0	326,104	709,520	654,502
Wind Resources	0	0	0	106,493	216,290
Seasonal Exchange Received	183,968	287,066	395,146	208,538	145,946
Wholesale Market Purchases (3)	1,393,718	2,571,228	2,411,210	898,613	1,210,699
Subtotal	4,776,928	5,972,116	6,709,931	7,900,806	8,182,502
Total Department Resources	13,245,614	12,672,505	10,651,319	14,803,123	14,294,970
Minus Offsetting Energy Sales:					
Firm Energy Sales and Marketing Losses (4)	219,793	249,321	310,670	396,862	378,433
Out of System Sales (5)	89,907	96,399	15,956	0	0
Seasonal Exchange Delivered	255,102	269,030	376,950	231,650	124,480
Wholesale Market Sales	2,673,542	2,023,060	468,827	4,647,945	4,262,041
Total Net Energy Resources (6)	10,007,270	10,034,695	9,478,916	9,526,666	9,530,016

Footnotes to Table:

(1) The Centralia Steam Plant was sold in May 2000.

(2) From October 1, 1996, through September 30, 2001, the amount of power purchased under the Bonneville power sale contract was limited to 195 average MW. Beginning on October 1, 2001, energy from Bonneville is based on the Block and Slice Power Sales contracts that took effect on that date.

(3) Purchases to compensate for low water conditions and to balance loads and resources. In 2000 and 2001, the Department's purchases of power in the wholesale market were unusually large, due to poor water conditions.

(4) Energy provided to Public Utility District No. 1 of Pend Oreille County under Article 49 of the Boundary Project's FERC license and to compensate the PUD for the Boundary Project's encroachment on Box Canyon. In 2002 and 2003, figures on this line also include incremental losses due to expanded activity in the wholesale market.

(5) Energy delivered to Nordstrom facilities in California.

(6) Firm energy required in the Department's service area.

Source: Seattle City Light, Finance Division

COST OF POWER SUPPLY: 1999-2003
($000) (UNAUDITED)

	1999	2000	2001	2002	2003
Wholesale Market Purchases [1]	$ 34,296	$ 212,402	$ 518,782	$ 12,440	$ 24,233
Other Power Purchases:					
Bonneville [2]	$ 33,089	$ 34,443	$ 66,824	$ 134,805	$ 157,088
Box Canyon	1,467	998	1,183	1,052	1,278
Priest Rapids	2,268	2,136	2,303	2,326	2,614
GCPHA	8,422	8,406	8,465	7,314	4,830
CSPE	0	0	0	0	0
High Ross	22,440	13,342	13,353	13,358	13,358
Lucky Peak	17,361	16,985	15,978	12,364	12,239
Metro Cogeneration	242	238	381	1,001	786
Klamath Falls	0	0	18,460	39,680	36,281
State Line Wind Project	0	0	0	6,474	11,326
Int and Ex of Wind Resources	0	0	0	2,417	1,551
Seasonal Exchange Received [3]	0	6,287	27,964	5,944	2,804
Other Services	240	0	10,094	1,141	13,204
BPA Billing Credits [4]	(3,845)	(3,531)	(3,713)	(3,067)	(2,965)
Subtotal	$ 81,684	$ 79,305	$ 161,292	$ 224,809	$ 254,394
Production:					
Centralia [5]	$ 14,098	$ 7,274	$ 0	$ 0	$ 0
Hydro Projects [6]	17,336	18,611	17,012	18,546	20,211
Control and Dispatch	4,146	5,285	6,065	6,282	7,251
Subtotal	$ 35,580	$ 31,170	$ 23,077	$ 24,829	$ 27,462
Total Power Supply Expense	$ 151,560	$ 322,878	$ 703,151	$ 262,078	$ 306,089
Minus Offsetting Power Revenue:					
Wholesale Power Sales	$ 51,466	$ 103,082	$ 73,899	$ 102,083	$ 137,651
Other Power Sales [7]	3,395	5,050	41,573	20,386	34,082
Net Cost of Power	$ 96,699	$ 214,746	$ 587,679	$ 139,609	$ 134,356
Total Energy Requirement (MWh)	10,007,270	10,034,695	9,478,916	9,526,666	9,530,016
Average Unit Cost (Dollars/MWh) [8]	$ 9.66	$ 21.40	$ 62.00	$ 14.65	$ 14.10

Footnotes to Table:

(1) Purchases to compensate for low water conditions and to balance loads and resources. Excludes wheeling costs. In 2000 and 2001, the Department purchased unusually large amounts of power in the wholesale market at high prices due to poor water conditions.

(2) From October 1, 1996, through September 30, 2001, the amount of power purchased under the Bonneville power sales contract was limited to 195 average MW. The cost of power in 2001, 2002 and 2003 reflects the increased amount of power available under the Block and Slice Power Sales contracts that took effect on October 1, 2001, and the rates charged by Bonneville under those contracts.

(3) Accounting Principles Board No. 29, Accounting for Nonmonetary Transactions, which requires the valuation of energy received and delivered under seasonal exchanges, was not implemented until 2000. The 1999 figures therefore do not impute value to energy delivered or received under seasonal exchanges.

(4) Billing credits received from Bonneville for the South Fork Tolt Project.

(5) The sale of the Centralia Steam Plant was completed in May 2000.

(6) Includes operation and maintenance costs only.

(7) Includes sales to Pend Oreille PUD under Article 49 of the Boundary Project license, valuation of seasonal exchange delivered and other energy credits.

(8) Average cost of power supplied to service area customers after recognizing the net revenue or cost associated with wholesale power sales and purchases.

Source: Seattle City Light, Finance Division

The Department's Resources

Boundary Hydroelectric Plant. The Boundary Project is located on the Pend Oreille River in northeastern Washington near the Canadian and Idaho borders, approximately 250 miles from Seattle. The plant was placed in service in 1967. It has a one-hour peak capability of 1,055 MW and expected energy output of 4,160,000 MWh under average water conditions. The Boundary Project is operated under a Federal Energy Regulatory Commission ("FERC") license which expires on October 1, 2011. The Department plans to apply for renewal of its Boundary license. The most recent FERC-mandated independent safety inspection in August 2000 concluded that the dam facilities were in good condition.

The Boundary Project's FERC license requires that up to 48 MW of the Boundary Project's capacity be assigned, at cost, to Public Utility District No. 1 of Pend Oreille County ("Pend Oreille PUD"). Due to Pend Oreille PUD's increasing loads and other contractual requirements, the amount of Boundary Project power assigned to Pend Oreille PUD is expected to increase to the maximum allowable amount of 48 MW in August 2005.

For a discussion of the impacts of fisheries issues on this facility, see "Environmental Matters—Endangered Species Act Issues." Encroachment of British Columbia Hydro and Power Authority's ("B.C. Hydro") Seven Mile Project on the Boundary Project is discussed below under "Ross, Diablo and Gorge Hydroelectric Plants."

Ross, Diablo and Gorge Hydroelectric Plants. The Ross, Diablo and Gorge hydroelectric plants are located on a ten-mile stretch of the Skagit River above Newhalem, Washington, approximately 80 miles northeast of Seattle. Power is delivered to the Department's service area via two double-circuit Department-owned transmission lines. The Ross Plant, located upstream of the other two projects, has a reservoir with usable storage capacity of 1,052,000 acre-feet. Because the Diablo Plant, with usable storage capacity of 50,000 acre-feet, and the Gorge Plant, with usable storage capacity of 6,600 acre-feet, are located downstream from the Ross Dam, their operation is coordinated with water releases from the Ross Reservoir and the three plants are operated as a single system. The combined one-hour peak capability of the three plants is 696 MW. Expected energy output in 2004 under average water conditions is 2,625,000 MWh.

These plants form the Skagit Hydroelectric Project and are licensed as a unit by FERC. FERC-required independent inspections of the Skagit Project in 2002 revealed no deficiencies. In 1995, FERC issued a new 30-year license for operation of the Skagit Project. As a condition of the new 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.

Although the original plans for the Skagit Project had included raising the height of Ross Dam by 122.5 feet to maximize the hydroelectric potential of the plant, the Canadian province of British Columbia (the "Province") protested on environmental grounds. After a protracted period of litigation and negotiation, an agreement (the "High Ross Agreement") was reached under which the Province agreed to provide the Department with power equivalent to the planned increase in the output of the Ross Plant in lieu of the Department's construction of the addition for 80 years commencing in 1986. The agreement is subject to review by the parties every ten years. The most recent review, concluded in 1998, did not result in any changes to the agreement.

The Department's annual payments to the Province include a fixed charge of $21.8 million annually through 2020, which represents the estimated debt service costs that would have been incurred had the addition been constructed and financed with bonds. In 2000, the Department began amortizing the remaining annual $21.8 million payments over the period through 2035. Payment of equivalent maintenance and operation costs and certain other charges began in 1986 and will continue for 80 years. The energy delivered under this agreement in 2003 amounted to 315,246 MWh. One-hour peak capability is 150 MW from April through October; from November through March, one-hour peak capability is equal to 532 MW minus the actual peak capability of the Ross Plant, given actual reservoir elevations behind Ross Dam.

If the Province discontinues power deliveries, the High Ross Agreement provides full authority to the Department to proceed with the originally proposed construction and obligates the Province to return to the Department sufficient funds to permit the Department to increase the height of Ross Dam and make other improvements as originally proposed. This obligation has been guaranteed by the Government of Canada.

As authorized in the High Ross Agreement, B.C. Hydro increased the reservoir elevation of its Seven Mile Project on the Pend Oreille River in the spring of 1988, thereby extending its reservoir across the international border to the tail-race of the Boundary Project. An 80-year contract between the City and B.C. Hydro was signed in 1989 to provide compensation to the Department for the encroachment of Seven Mile Reservoir on the Boundary Project.

Cedar Falls Hydroelectric Plant. The Cedar Falls Hydroelectric Plant ("Cedar Falls"), built in 1905, is located on the Cedar River, approximately 30 miles southeast of Seattle. Cedar Falls was constructed before the adoption of the Federal Water Power Act of 1920 and is not subject to licensing by FERC. Cedar Falls power is delivered through an interconnection with Puget Sound Energy. The one-hour peak capability of the plant is 30 MW. Energy production in 2003 at Cedar Falls was 63,701 MWh.

Newhalem Hydroelectric Plant. The Newhalem Hydroelectric Plant ("Newhalem"), located on Newhalem Creek, a tributary of the Skagit River, was built in 1921 to supply power for the construction of the Skagit Project. The plant was rebuilt and modernized in 1970. It is operated under a FERC license which expires January 31, 2027. The plant's power is delivered over Department-owned transmission lines. The one-hour peak capability of the plant is 2.0 MW. Energy generation in 2003 was 8,213 MWh.

South Fork Tolt River Hydroelectric Plant. The South Fork Tolt River Hydroelectric Plant (the "Tolt Project") was placed in commercial operation in 1995. The Tolt Project operates under a 40-year FERC license which expires in 2028. The one-hour peak capability of the installed unit is 16.8 MW. Energy production at the Tolt Project in 2003 was 49,000 MWh. To reduce its cost of power from the Tolt Project, the Department entered into a Billing Credits Generation Agreement with Bonneville in 1993, under which Bonneville makes payments to the Department that have the effect of making the cost of power from the Tolt Project approximately equal to the cost of equivalent power from Bonneville. Payments to the Department under the agreement commenced in 1996 and amounted to $3.0 million in 2003.

Purchased Power Arrangements

In 2003, the Department purchased approximately 48.8 percent of its total available system energy from other utilities in the region, including Bonneville, under long-term purchase contracts. Some of these agreements with other utilities provide that the Department is obligated to pay its share of the costs of the generating facilities providing the power, including debt service on bonds issued to finance construction, whether or not it receives any power. The Department has covenanted to treat payment of such costs as part of its purchased power expense and includes such costs in its operating and maintenance expenses.

The Department has in the past and may in the future purchase power under the Western Systems Power Pool Agreement and the Block and Slice Power Sales Agreement described immediately below. Those agreements include an obligation on the part of the Department to post collateral contingent upon the occurrence or nonoccurrence of certain future events within the control of the Department, such as future credit ratings or payment defaults. The Department also has entered, and may in the future enter, into agreements that include an obligation on the part of the Department to make payments or post collateral contingent upon the occurrence or nonoccurrence of certain future events that are beyond the control of the Department, such as future changes in gas prices. Such obligations may be characterized as maintenance and operation charges, and thus would be payable from Gross Revenues of the Light System prior to the payment of Parity Bond debt service.

The Bonneville Power Administration. Bonneville markets power from 30 federal hydroelectric projects, from several non-federally-owned hydroelectric and thermal projects in the Pacific Northwest and from various contractual rights with installed peak generating capacity of 24,080 MW and a firm energy capability of approximately 8,500 average MW (the "Federal System"). These projects are built and operated by the

United States Bureau of Reclamation (the "Bureau") and the United States Army Corps of Engineers (the "Corps") and are located primarily in the Columbia River basin. The Federal System currently produces approximately 45 percent of the region's energy requirements. Bonneville's transmission system includes over 15,000 circuit miles of transmission lines, provides about 75 percent of the Pacific Northwest's high-voltage bulk transmission capacity and serves as the main power grid for the Pacific Northwest. Its service area covers over 300,000 square miles and has a population of about ten million. Bonneville sells electric power at cost-based wholesale rates to more than 130 utility, industrial and governmental customers in the Pacific Northwest. Bonneville also sells power directly to eight industrial customers in the region. Bonneville is required by law to give preference to government-owned utilities and to customers in the Northwest region in its wholesale power sales.

A Block and Slice Power Sales Agreement with Bonneville provides for purchases of power by the Department over the ten-year period beginning October 1, 2001. Under the contract, power is delivered in two forms: a shaped block (the "Block") and a Slice. Through the Block product, power is delivered to the Department in monthly amounts shaped to the Department's monthly net requirement, defined as the difference between the Department's projected monthly load and the resources available to serve that load under critical water conditions. The original contract provided for delivery of 163.8 average MW annually as a Block for the period from October 1, 2001, through September 30, 2006, and 278.2 average MW from October 1, 2006, through September 30, 2011. The amount of Block power available to the Department has been reduced by 41.5 average MW since the inception of the contract, pursuant to agreements with Bonneville through which Bonneville purchases energy savings realized by the Department's conservation programs. The Department's entitlement to Block power is reduced by the amount of savings purchased. Through November 30, 2004, the Department had received $35.1 million in payments from Bonneville for conservation savings and expects to receive an additional $16.4 million through June 30, 2006.

Under the Slice product, the Department receives a fixed 4.6676 percent of the actual output of the Federal System and pays the same percentage of the actual costs of the system. Payments for the Slice product are subject to an annual true-up adjustment to reflect actual costs. Power available under the Slice product varies with water conditions, federal generating capabilities and fish and wildlife restoration requirements. Under the most recent estimates of the capability of the Federal System, energy available to the Department through the Slice product is expected to average 443 average MW over all water conditions. Under critical water conditions, the Slice product provides 334 average MW of energy.

Bonneville's Record of Decision establishing fees and charges effective October 1, 2001 included a Cost Recovery Adjustment Clause ("CRAC") which authorized Bonneville to increase its power rates under three conditions. First, a Load-Based CRAC adjustment is authorized to cover the additional cost of purchasing power in the wholesale market to serve increases in demand from Bonneville customers that cannot be accommodated by the Federal System. Second, a Financial-Based CRAC can be imposed if higher than expected market prices cause Bonneville's accumulated net revenues to fall below a threshold level. Finally, a Safety-Net CRAC is authorized in any year in which Bonneville projects that there is a less than 50 percent probability that it will be able to pay all of its financial obligations, including its debt service payments to the U.S. Treasury. The Load-Based CRAC applies to both the Block and the Slice products and is adjusted at six-month intervals; the Financial-Based CRAC and the Safety-Net CRAC apply only to Block purchases. The table below shows the CRAC adjustments that have been applied by Bonneville since September 30, 2001.

BONNEVILLE CRAC ADJUSTMENTS

	Block				Slice
Effective Date	**Load-Based**	**Financial-Based**	**Safety Net**	**Total**	**Load-Based**
October 1, 2001	46.00%			46.00%	46.37%
April 1, 2002	39.08%			39.08%	40.03%
October 1, 2002	31.88%	10.97%		42.85%	32.35%
April 1, 2003	38.53%	10.97%		49.50%	39.51%
October 1, 2003	21.29%	12.28%	10.09%	43.66%	21.55%
April 1, 2004	24.63%	12.28%	10.09%	47.00%	25.13%
October 1, 2004	21.66%	11.16%	0.00%	32.82%	21.93%

In addition to paying rates that included the CRAC adjustments, the Department also made a Slice true-up payment of $10.7 million in 2003 to reconcile the difference between actual Slice costs and the estimates on which the Slice Load-Based CRAC were based. The Department received a Slice true-up credit of $6.4 million in 2004 and expects to make a true-up payment of $2.1 million in 2005.

The Department is required by ordinance to pass through to its customers the effect of changes in Bonneville's rates under the various CRAC provisions without any further action by the Council. See "The Department—Retail Rates." The Department has passed through the impact of the Bonneville CRAC adjustments and Slice true-ups by adjusting energy charges for all rate classes in the following amounts:

ENERGY CHARGE ADJUSTMENTS

	Non-Low-Income Rate Classes		Low-Income Rate Classes	
Effective Date	**Adjustment ($/kWH)**	**Cumulative Adjustment ($/kWH)**	**Adjustment ($/kWH)**	**Cumulative Adjustment ($/kWH)**
October 1, 2001	0.0055	0.0055	0.0028	0.0028
April 1, 2002	(0.0007)	0.0048	(0.0004)	0.0024
April 1, 2003	0.0008	0.0056	0.0004	0.0028
April 1, 2004	(0.0013)	0.0043	0.0006	0.0022

The unit cost of power purchased under the Bonneville contract in 2003 was $33.33 per MWh. The Department's financial projections are based on Bonneville's forecast of CRAC adjustments and Slice true-up payments through September 30, 2006. Fees and charges for power beyond September 30, 2006 have not yet been determined by Bonneville. The Department's financial forecast assumes that the rates in effect in the twelve months ending September 30, 2006, will continue through the remainder of the contract period.

Energy Northwest (formerly known as the Washington Public Power Supply System). The City is a member of Energy Northwest, a municipal corporation and joint operating agency organized under State law that currently has, as members, ten public utility districts and three municipalities, all located within the State. Energy Northwest has the authority to acquire, construct and operate plants, works and facilities for the generation and transmission of electric power.

Energy Northwest was engaged in the construction of five nuclear generating facilities termed Projects Nos. 1, 2, 3, 4, and 5. Project No. 2 was placed in commercial operation in December 1984 and the other projects were terminated in the 1980s. Pursuant to separate Net Billing Agreements with Energy Northwest and Bonneville with respect to Projects Nos. 1, 2 and 3 (the "Net Billed Projects"), the Department is obligated unconditionally to pay Energy Northwest its pro rata share of the total annual costs of the Net Billed Projects, including debt service. The payments are required to be made whether or not construction is completed, delayed or terminated, or operation is suspended or curtailed. Payment by Bonneville to Energy Northwest of the Department's share of its total annual cost of the Net Billed Projects is made by a crediting arrangement whereby Bonneville credits against amounts that the Department owes Bonneville for the purchase of wholesale power an amount equal to the Department's share of the total annual cost of each Net Billed Project. The agreements provide that the Department purchase from Energy Northwest and, in turn, assign to Bonneville a maximum of 8.605 percent, 7.193 percent and 5.043 percent of the capability of Projects Nos. 1 and 2 and Energy Northwest's ownership share of Project No. 3, respectively. The Department's respective shares may be increased by not more than 25 percent upon default of other public agency participants. To the extent the Department's share of such annual costs exceeds amounts owed by the Department to Bonneville, Bonneville is obligated, after certain assignment procedures, to pay the amount of such excess to the Department as reimbursement or to Energy Northwest directly, but only from funds legally available for that purpose.

Under the Net Billing Agreements, the Department's electric revenue requirements are not affected directly by the cost of completion or termination of the Net Billed Projects, but such revenue requirements may be affected to the extent that the costs of such Projects result in increases in the wholesale power rates of Bonneville. Bonneville has been paying principal of and interest on Project No. 1 revenue bonds since 1980, on Project No. 2 revenue bonds since 1977 and on Project No. 3 revenue bonds since 1982. Bonneville, in projecting its revenue requirements and wholesale power rates, includes in its estimate the principal of and interest on those bonds issued and projected to be issued and Energy Northwest's operating expenses for the Net Billed Projects.

Klamath Falls Cogeneration Project. An agreement with the City of Klamath Falls, Oregon, provides for the purchase of energy and capacity from the Klamath Falls Cogeneration Project, a 500 MW cogeneration facility consisting of a combined-cycle combustion turbine fueled by natural gas. Under the contract, the Department will receive 100 MW of capacity from the project for the five-year period ending in July 2006. The Department received 654,502 MWh of energy under this agreement in 2003 at an average cost of $55.43 per MWh.

Lucky Peak Hydroelectric Power Plant. The Lucky Peak Hydroelectric Power Plant ("Lucky Peak") was developed by three Idaho irrigation districts and one Oregon irrigation district (the "Districts") and began operation in 1988. Its FERC license expires in 2030. The plant is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. The rated capability of the three generating units at the plant is 101 MW. Energy generation in 2003 was 292,348 MWh. Since generation is concentrated in the summer months, the plant has no peak capability during the Department's winter peak period.

The Department entered into a 50-year power purchase and sales contract in 1984 with the Districts under which the Department will purchase all energy generated by Lucky Peak, in exchange for payment of costs associated with the plant and royalty payments to the Districts. The Department also signed a transmission services agreement with Idaho Power Company ("Idaho Power") to provide for transmission of power from Lucky Peak to a point of interconnection with the Bonneville system. The Department sold the actual net output of the plant for the period from May 1, 2003, through November 30, 2004, at a price equal to the Dow Jones Mid-Columbia Index plus $3.25 per MWh and has contracted to sell the actual output of the plant in calendar year 2005 at a price of $52 per MWh..

Priest Rapids Hydroelectric Plant. Under an agreement effective through October 31, 2005, the Department receives eight percent of the output of the Priest Rapids Development ("Priest Rapids") which, together with the Wanapum Development, constitutes the Priest Rapids Project and is owned and operated by Public Utility District No. 2 of Grant County ("Grant PUD"). The Priest Rapids Development has an installed capacity of 855 MW. The Department's share of Priest Rapids generation in 2003 was 310,716 MWh.

In 1995, certain Idaho and Snake River cooperatives filed a complaint with FERC in which they sought entitlement to allocation of power from Priest Rapids under any new license. FERC ruled in 1998 that, effective November 1, 2005, 70 percent of the Priest Rapids Project's output would be allocated to the licensee, with the remaining 30 percent available for sale pursuant to market-based principles to entities in the broad seven-state Northwest region, while giving certain Idaho cooperatives and the current power purchasers a priority right. FERC also issued an order permitting any entity, not just Grant PUD or another Washington public agency, to file a competing license application. These proceedings could impact the amount of power generated at Priest Rapids and the Department's allocation of power upon expiration of the current contract. See "Environmental Matters—Endangered Species Act Issues."

Contracts executed in 2002 with Grant PUD provide for the allocation of power and other benefits from the Priest Rapids and Wanapum Developments to the Department over the period from November 1, 2005, through the end of the new FERC license period. Under the terms of these contracts the Department expects to purchase a share of the firm and nonfirm power allocated to Grant PUD that is surplus to the PUD's load requirements. The amount of power available from Grant PUD under these provisions will decline over time as the PUD's load, and therefore its claim on the 70 percent of the Priest Rapids Project's output that is allocable to the PUD, increases. In addition, the Department has contracted to receive a share of the net revenue derived from the sale of the 30 percent share of the Priest Rapids Project's output that will be sold pursuant to market-based principles in the seven-state Northwest region under the terms of the FERC order. The Yakama Indian Nation has filed a petition with FERC challenging the new contracts signed by Grant PUD.

Grand Coulee Project Hydroelectric Authority. The Department, in conjunction with the City of Tacoma, Department of Public Utilities, Light Division ("Tacoma"), has power purchase agreements with three Columbia Basin irrigation districts for acquisition of power from five hydroelectric plants under 40-year contracts expiring between 2022 and 2027. These plants, which utilize water released during the irrigation season, are located along irrigation canals in eastern Washington and have a total installed capacity of approximately 129 MW. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between the Department and Tacoma. In 2003 the Department received 235,496 MWh from the project.

Box Canyon Hydroelectric Plant. The Department purchases power from the Box Canyon Hydroelectric Plant ("Box Canyon") owned and operated by Pend Oreille PUD. The purchase contract, which extends until August 1, 2005, provided the Department with 47,452 MWh of energy in 2003.

West Point Sewage Treatment Plant Cogeneration. In 1982, the Municipality of Metropolitan Seattle ("Metro," now part of King County) and the Department executed a contract for the purchase of the electrical output of a cogeneration plant located at the County's West Point Sewage Treatment Plant. The project uses methane gas produced at the treatment plant to provide approximately 1.2 MW of one-hour peak capability from three reciprocating engines. The Department received 14,333 MWh of energy under the agreement in 2003. The Department's contract with Metro expired on August 31, 2003, and has been extended pending completion of negotiations between the two parties. Metro plans to supply most of its own requirements for electrical power from an expanded cogeneration plant at West Point and is likely to rely on the Department only for back-up power. The Department does not expect to purchase power from Metro beyond 2004.

Wind Generation. An October 2001 agreement with PPM provides for the Department's purchase of wind-generated energy and associated environmental attributes (such as offsets or emission reduction credits) primarily from the State Line Wind Project in eastern Washington and Oregon. Under the agreement, the Department received wind energy with an aggregate maximum delivery rate of 50 MW per hour from January 1, 2002, through July 31, 2002, 100 MW per hour from August 1, 2002, through December 31, 2003, and 125 MW per hour from January 1, 2004, through June 30, 2004. From July 1, 2004, through the end of the contract on December 31, 2021, the maximal delivery rate will be 175 MW per hour. Energy delivered under the contract is expected to average about 30 percent of the maximum delivery rate. The Department also entered into a ten-year agreement to purchase integration and exchange services from PacifiCorp and a 20-year agreement to sell integration and exchange services to PPM. The Department received 216,290 MWh of wind energy under the PPM contract in 2003.

Exchange with Northern California Power Agency ("NCPA"). The NCPA exchange agreement provides for the Department to deliver 60 MW of capacity and 90,580 MWh of energy to NCPA in the summer. In return, NCPA delivers 46 MW of capacity and 108,696 MWh of energy to the Department in the winter. Deliveries to NCPA started in 1995 and will continue until the agreement is terminated. Either party has the right to terminate the agreement after May 31, 2014.

Wholesale Market Sales and Purchases

The Department has historically bought and sold energy in wholesale power markets to balance its loads and resources. The amount of wholesale energy purchased or sold has varied with water conditions and with changes in the Department's firm resource base. Prior to 1996, when power available to the Department at critical water levels was roughly equal to its load, the Department typically had surplus power available to sell in the wholesale market when water conditions were above critical levels. With the limitation of its Bonneville purchases in 1996 and the sale of the Centralia Steam Plant in 2000, the Department faced energy deficits at critical water levels, and expected to be a net purchaser of energy in the wholesale market under average water conditions. Acquisition of additional resources beginning in 2001 from Bonneville, the Klamath Falls Cogeneration Project and the Stateline Wind Project, together with a reduction in retail consumption resulting from conservation programs and the effect of rate increases, has substantially changed the relationship between the Department's power resources and retail load. With its current resource portfolio, the Department expects to have surplus power available for sale in the wholesale market through 2011, even under adverse water conditions.

The table below displays the Department's purchases and sales of power in the wholesale market over the period from 1999 through 2003. In 2000 and 2001 a severe regional drought caused the Department to purchase large amounts of power in the wholesale market at extraordinarily high prices. The net cost of the Department's wholesale market transactions was $109.3 million in 2000 and $444.9 million in 2001. In 2002 and 2003, with additional power available from the Department's recently acquired resources, substantial energy surpluses were available for sale in the wholesale market. The Department realized net revenue of $89.6 million in 2002 and $113.4 million in 2003 from its wholesale market transactions.

WHOLESALE MARKET SALES AND PURCHASES
(UNAUDITED)

	1999	2000	2001	2002	2003
Wholesale Market Purchases (MWh) (1)	1,393,718	2,571,228	2,411,210	898,613	1,210,699
Cost of Purchases ($000s)	$37,296	$212,402	$518,782	$12,440	$24,233
Average Cost ($/MWh)	$26.76	$82.61	$215.15	$13.84	$20.02
Wholesale Market Sales (MWh)	2,673,542	2,023,060	468,827	4,647,945	4,262,041
Revenue from Sales ($000s)	$51,466	$103,082	$73,899	$102,083	$137,651
Average Revenue ($/MWh)	$19.25	$50.95	$157.63	$21.96	$32.30
Sales Net of Purchases (MWh)	1,279,824	(548,168)	(1,942,383)	3,749,332	3,051,342
Net Revenue ($000s)	$14,170	($109,320)	($444,883)	$89,643	$113,418

(1) In 2000 and 2001, purchases in the wholesale market were at unusually high levels due to poor water conditions. In 2002 and 2003, the net amount of energy available for sale in the wholesale market was considerably higher than in 2000 and 2001, due to improved water conditions and the acquisition of additional firm resources by the Department.

Source: Seattle City Light, Finance Division

Risk Management

The Department's exposure to risk is managed by a Risk Management Committee ("RMC") consisting of the Deputy Superintendents for Finance and Administration, Power Management and Generation, the Department's Director of Strategic Planning and the Department's Risk Officer. The RMC is responsible for managing both market risk and credit risk.

Market Risk. The RMC meets weekly to review and adjust the Department's near-term and long-term strategy for marketing surplus energy or, in periods of deficit, for purchasing energy to meet load. The Department executes trades in the wholesale market to meet load during periods of resource deficit, to dispose of energy that is surplus to the needs of the Department's retail customers and to optimize the value of the Department's hydroelectric resources by purchasing wholesale energy in off-peak hours, when prices generally are low, and selling energy in the peak hours, when prices are generally higher. The Department does not engage in speculative trading in the wholesale market.

Credit Risk. The Department's Credit Committee, which reports to the RMC, consists of the Deputy Superintendent for Power Management and the Department's Finance Director, Director of Customer Accounts and Risk Manager. The Credit Committee meets monthly to manage the credit risk associated with the Department's marketing activities. Finance Division staff review the creditworthiness of counterparties with which the Department trades power in the wholesale market and recommends credit limits for each counterparty. Where appropriate, credit enhancements are recommended for counterparties that do not meet standards of creditworthiness adopted by the Credit Committee. Finance and Power Management staff monitor trading activity to ensure that credit limits established by the Credit Committee are not exceeded and provide status reports to the Credit Committee.

Transmission

Department-Owned Transmission. The Department operates 656 miles of transmission facilities. The principal transmission line transmits power from the Skagit Project to the Department's service area. In 1994, the Department signed an agreement with Bonneville for the acquisition of ownership rights to 160 MW of transmission capability over Bonneville's share of the Third AC Intertie, which connects the Northwest region with California and the Southwest. The benefits from this investment include avoidance of Bonneville's transmission charges associated with power sales and exchanges over the Intertie and the ability to enter into long-term firm contracts with out-of-state utilities. The Oregon Department of Revenue has initiated litigation to collect a property tax on the Department's capacity rights in the Third AC Intertie. The potential liability is about $500,000 per year. Summary judgment motions were argued in the Oregon Tax Court in May 2003. An appeal to the Oregon Supreme Court is likely to follow the Tax Court's disposition of the case, and an appeal to the United States Supreme Court is possible.

Transmission Arrangements with Bonneville. Contracts with Bonneville provide the Department with 1,962 MW of transmission capacity under a point-to-point ("PTP") transmission service agreement for the period from October 1, 2001, through July 31, 2025. The Department's rights under the current PTP contract are expected to be preserved under Grid West. However, the rates that will apply to services provided by Grid West are uncertain, as are the rates likely to be charged by Bonneville if the formation of Grid West is delayed or abandoned. In its financial forecast, the Department has assumed that wheeling costs will increase by 22 percent from 2004 through 2008.

Power supplied to the Department by B.C. Hydro under the High Ross Agreement is transmitted over Bonneville's lines under a second PTP transmission service agreement extending through 2005. The High Ross PTP contract was assigned to B.C. Hydro in 1999. B.C. Hydro in turn reassigned the contract to the British Columbia Power Exchange Corporation ("Powerex"). Under the assignment agreement provisions, Powerex pays Bonneville directly for all costs associated with the PTP contract. The Department expects to renew this PTP contract with Bonneville in 2006 for at least an additional ten-year term, and simultaneously to renew the assignment arrangement with B.C. Hydro for the same term. See "Power Resources—The Department's Resources."

Other Transmission Contracts. The Department also transmits power under contracts with Idaho Power for the transmission of power from the Lucky Peak Project, with Avista for transmission of power from the Grand Coulee Project Hydroelectric Authority; with Puget Sound Energy for transmission of power from the Cedar Falls and South Fork Tolt Projects, and with other utilities.

Additional purchases of transmission on a nonfirm basis may be required in the future in order to accommodate the Department's sales of power in the wholesale market during the spring runoff.

Conservation

The Department has pursued a policy of managing as well as meeting energy demand. As a result of the "Energy 1990" study, prepared in 1976, the City decided to pursue conservation as an alternative to participating in Energy Northwest's Projects Nos. 4 and 5. During the 1980s, single-family residential measures dominated the Department's conservation program. Conservation incentive programs in the commercial, industrial and multifamily sectors were added in the 1990s. Because commercial and industrial measures are more cost-effective, the majority of new energy savings acquired in recent years has come from these sectors, a trend that is projected to continue into the future. Since 1977, the Department has achieved almost 107 average MW of energy savings through conservation.

The 2000 Strategic Resources Plan called for the Department to accelerate the pace of energy savings through conservation. In the spring of 2001, a work plan was developed which increased the targeted level of energy savings to be achieved annually through conservation programs from six average MW to nine average MW per year. To meet this higher target, the work plan called for the Department to continue to operate its core conservation initiatives for all customer groups while adding some new programs and services to address service gaps.

The power sales contract with Bonneville that took effect on October 1, 2001, provides a credit of $0.50 per MWh against the amounts payable under Bonneville's rate schedules for investments in conservation and renewable resources. In 2003, credits totaling $2.1 million were applied against the cost of power from Bonneville.

Under agreements with Bonneville in 2002 and 2003, Bonneville will pay the Department $51.5 million for conservation savings to be achieved over the period from October 1, 2001, through September 30, 2006. As part of these agreements, the Department's purchases of power from Bonneville under the Block product are reduced by the amount of conservation savings purchased by Bonneville. See "Power Resources—Purchased Power Arrangements—Bonneville Power Administration."