PROPOSED
REVENUE REQUIREMENTS
ANALYSIS

2010

Seattle City Light
October 2009

T A B L E   O F   C O N T E N T S

Introduction

I.1 Introduction

This report, *Proposed Revenue Requirements Analysis for 2010 (RRA)*, is the initial step in proposing new rates needed to collect sufficient revenues from customers so that City Light can provide for its operations, maintenance and capital needs as well as meet its financial policies. The financial policies were most recently articulated by the City Council in Resolution 30761 in May 2005 and Resolution 30933 in November 2006. The current rate review process includes some proposed revisions to the financial policies that are described in the Summary chapter.

The *2010 Revised Budget* is the basis for the *Proposed Revenue Requirements Analysis for 2010* proposed rates. The Budget identifies the activities and resources necessary to achieve City Light's mission, i.e., "exceed our customers' expectations in producing and delivering environmentally responsible, safe, low cost and reliable power."

The primary goal of the current rate-setting process is to propose gradual increases in rates for the three-year period 2010-2012 that will strengthen City Light's financial position while minimizing rate increases in any single year. The rate proposal for 2010 is the first year of this three-year plan and the only year for which City Light is currently seeking approval by the City Council. The proposed rate increases for 2011 and 2012 are included in the financial forecast and displayed in the Summary chapter of this RRA report for planning purposes, to provide a context for the 2010 rate proposal and related proposals to revise City Light financial policies. The proposed 2010 rates are displayed in the rate schedules in Appendix 7.

More details about the total rate-setting process can be found in the document, *Seattle City Light Guide to Rate Making*, prepared for the Seattle City Light Rates Advisory Committee by the Financial Planning Unit in September 2009.

I.2 Revised Structure of *Proposed Revenue Requirements Analysis Report*

Before explaining the revised structure of this *RRA*, it is critical to recognize that City Light is guided by City Council resolutions in calculating proposed rates. Central to that guidance is an emphasis on having sufficient money (cash) to pay outstanding debt service obligations. Hence, the focus of this *RRA* is on Cash Available for Debt Service and Cash from Operations.

Previous *RRAs* were structured around entries in the Department's income statement. This approach has been abandoned because there are expenses and revenues that appear in the income statement that are not cash, for instance values ascribed to energy exchanges where no cash is involved. There also are cash flows that are not part of the income statement. Some examples of this are expenditures for toxic clean-up that were reported on the income statement in a prior year, cash contributions from suburban customers that are spread equally over 25 years following completion of undergrounding projects but the entire amounts to be received are recorded as income in the year that these projects are completed, and cash proceeds from property sales that are different from the related gains or losses reported on the income statement. Hence, continued focus on an income statement approach to derive proposed retail rates poses some practical problems of reconciling the necessity to have sufficient cash to pay debt service with a report that does not focus on cash transactions. An income statement is, of course, still of interest for other purposes and it is in Table 1.01 in Appendix 2.

This *RRA* emphasizes a cash-based approach to developing proposed retail rates. It will become apparent that not all cash transactions expected in the next year (flows in and out) have an immediate bearing on the proposed retail rate. But the cash transactions can be put into explicit categories; there are categories which have direct effects on the immediately proposed retail rate, and there are other categories that do not affect next year's proposed rate but may affect rates in the future. These different categories are described below.

The emphasis on cash in this *RRA* is shown in the titles to the chapters which, typically, begin with "Cash From …" or "Cash To …". The inclusion of "From" or "To" in the title is to emphasize the direction of the cash flows. "Cash From…" is the cash coming in to the Department from some other source. "Cash To…" is the cash going out of the Department to another entity or being used for another purpose within the Department, and therefore not available to cover debt service, pay for capital expenditures or increase the year-end cash balance.

I.3 Organization of the *Proposed Revenue Requirements Analysis 2010*

The Summary chapter discusses the major reasons for the change in revenue requirements between the average forecast for 2007-2008 in the 2007-2008 Rate Study and the current forecast for 2010. Wherever this 2010 *RRA* document refers to 2007-2008 amounts, it refers to the average amounts forecasted for those two years in the 2007-2008 Rate Study. This *RRA* does not compare currently projected 2010 revenue requirements with actual 2007-2008 financial results, nor does it compare them with prior forecasts of 2010 revenue requirements.

The first nine chapters discuss the cash sources and uses that directly affect 2010 revenue requirements. The subsequent chapters discuss sources and uses of cash that do not directly affect 2010 revenue requirements but are integral to the planning and operation of the Department and can affect, for example, future debt that will have to be repaid from future rates. Since these subsequent chapters deal with cash sources and uses that have a greater effect on future rates than on rates in 2010, their analysis often presents information about future years beyond 2010 in order to provide a context for what is planned to occur in 2010.

Chapters 1-3 of this *RRA* describe the sources of cash available for debt service coverage. The largest source of cash, Cash from Retail Power Sales before Discounts, is described in Chapter 1. Cash from Retail Power Sales before Discounts for 2010 is the retail revenue requirement target for 2010. The second largest source of cash and also the most volatile source is Cash from Wholesale Power Sales, Net, which is described in Chapter 2. Chapter 3 describes Cash from All Other Sources, which include a wide variety of revenues from power-related services as well as nonpower fees and service charges.

Chapters 4-8 describe uses of cash that reduce the amount available for debt service coverage. Cash to Power Contracts, described in Chapter 4, includes expenditures for power purchased from the Bonneville Power Administration (BPA), City Light's largest long-term power contract, as well as expenditures for purchases of both power and transmission under other long-term contracts. Chapter 5 describes Cash to Operations, the cash outflows associated with the operation and maintenance (O&M) expenses of the utility. These include the cost of operating and maintaining City Light-owned generation, transmission, distribution facilities and equipment, customer accounting and advisory expenses, direct conservation expenses and administration and general expenses. They also include power contract administration, power marketing and power system control center expenses.

Chapter 6 describes Cash to Rate Discounts, as well as other services that City Light provides to low-income customers. Chapter 7 describes Cash to Uncollectable Revenue and Chapter 8 describes State Taxes and Franchise Payments. City taxes are subordinate to debt service and from a cash flow perspective are in another category of expenses which are discussed in Chapter 10. But the calculation of City taxes is analogous to the calculation of State taxes, hence City taxes are also discussed in this chapter.

Chapter 9 describes Cash Available for Debt Service. This is a bottom-line target amount determined by the cash transactions in Chapters 2-8 and the Department's financial policies and is a critical factor in determining revenue requirements described in Chapter 1.

Chapters 10-12 describe uses of cash that do not directly affect Cash Available for Debt Service. Because of this, they also have no direct impact on revenue required from retail customers for 2010 though they may have an effect on debt service and rates in future years. Chapter 10 describes Cash to City Taxes. Chapter 11 describes Cash to All other Purposes, which includes expenditures on materials and supplies and changes in receivables and payables. Chapter 12 describes cash to debt service, relating it both to debt service on existing outstanding bonds and the forecast of debt service on bonds to be issued in 2010-2012.

Chapters 13-15 describe sources of funding for capital expenditures. Chapter 13 discusses Cash from Operations, the amount of cash from operating revenues remaining after cash requirements for all operating expenses, including debt service, have been met. Chapter 14 describes Cash from Contributions, which includes contributions in aid of construction, capital grants and fees, and funding for conservation. Chapter 15 discusses Cash from Bond Proceeds, which is proceeds from bond issuance net of cash required for debt issue costs, and, therefore, is slightly less than the amount of debt issued.

Chapter 16 describes Cash to Capital, Conservation and Deferred O&M. This chapter discusses major initiatives in the Department's Capital Improvement Program (CIP), classifying CIP expenditures according to functional categories: generation, transmission, distribution, and general plant. This chapter also discusses the Conservation Five-Year Plan, Environmental Mitigation, deferred O&M expenditures, and capitalized expenditures for power purchased under the High Ross agreement with B.C. Hydro. Capital expenditures in 2010 do not affect rates in 2010. Any debt acquired in 2010 to help fund these capital projects will affect future debt service and, hence, increase future rates, but current capital projects have no effect on rates in the near term.

This *RRA* also includes appendices. Appendix 1 presents a Summary report for 2009-2012 and Cash Flow and Key Financial Indicators reports for 2009-2019. Appendix 2 presents the Financial Planning Model reports for 2009-2012. Appendix 3 presents a summary of the proposed changes to the Department's financial policies. Appendix 4 presents a summary of a proposed Power Revenue Adjustment Mechanism that will ensure stable cash flows from operating revenues. Appendix 5 presents management decisions taken during the current rate-setting process in order to reduce the size of the 2010 rate increase. Appendix 6 presents components of the increase in Cash to Operations since the 2007-2008 Rate Study. Appendix 7 presents the Proposed Retail Rate Schedules Effective January 1, 2010. Appendix 8 presents relationships among cash flow table elements and the debt service coverage ratio.

This *RRA* has been designed to provide extensive detail about the derivation of the revenue requirements for 2010. However, further details, e.g., relating to forecasting models, are available from the Financial Planning Unit of Seattle City Light.

Summary of the Revenue Requirements Analysis for 2010

S.1 Overview

This chapter presents a summary of changes in revenue requirements underlying the rate adjustments proposed to take effect on January 1, 2010. It also shows revenue requirements for 2011 and 2012, consistent with City Light's proposed three-year plan to restore the Utility's financial strength and fill the financial gap identified in 2009. It is expected that a full rate review process will be undertaken in 2010 to set rates for 2011 and 2012 consistent with that plan and the budgets for those years. The revenue requirements forecast for 2010-2012 allows for gradual increases in average rates to be paid by retail customers, keeping these increases as low as possible while satisfying Council-mandated financial policies. This forecast assumes that these policies will be modified, as described later in this document.

Resolution 30761, passed by the City Council in May 2005, and Resolution 30933 passed in November 2006, which established current financial policies for City Light, require City Light to use a "flow of funds" approach (like cash flow) in discussing its revenue requirements forecast. Using this approach, Section S.2 describes how the revenue requirements are determined and demonstrates that the Department expects to meet its financial policy targets. Section S.3 identifies the major sources of change between the forecast for 2007-2008, which is the basis for the current rates, and the proposed 2010 revenue requirements. Section S.4 identifies the major decisions made by City Light's management team in order to reduce the 2010 revenue requirements without revisions to current financial policies.

S.2 How Revenue Requirements Are Determined

The objective of the Revenue Requirements Analysis is to determine the amount of revenue from customers that must be collected by the Department in a given calendar year to cover operating costs in that year and meet financial policies established by City Council resolution.

Operating costs and capital expenditure levels are set during the biennial budget process. Levels of expenditure are set so that Seattle City Light will have the staff and financial resources necessary to support key activities and projects. The amount of revenue required from customers is calculated after operations and maintenance expenses, capital expenditures, other sources of revenue, and cash balances required by financial policy are projected.

Table 1 shows the flow of funds in the financial forecast for 2009-2012. City Light proposes to set rates so that expected revenues from customers before discounts will total $587.8 million in 2010 and increase to $629.6 million in 2011 and $690.3 million in 2012. These amounts are the revenue requirements for those years. At those levels, revenues from customers plus wholesale power and other expected sources of revenue will be sufficient to pay for City Light's power contracts, operations, debt service, taxes and other expenditures and also meet its financial policy targets, assuming that these targets are modified as described below.

Table 1

Cash Flow
(All Dollar Figures in Millions)

	2009	2010	2011	2012
Cash from Retail Power Sales before Discounts	$540.1	$587.8	$629.6	$690.3
Cash from Wholesale Power Sales, Net	69.2	120.0	116.1	90.5
Cash from All Other Sources	72.7	70.2	71.3	68.2
Cash to Power Contracts	-260.8	-293.4	-284.1	-274.4
Cash to Operations	-193.4	-201.7	-217.8	-219.0
Cash to Rate Discounts	-5.5	-6.1	-6.5	-7.0
Cash to Uncollectable Revenue	-4.9	-5.3	-5.7	-6.2
Cash to State Taxes and Franchise Payments	-28.0	-30.3	-32.0	-34.6
Cash Available for Debt Service	**$189.3**	**$241.1**	**$270.9**	**$307.8**
Cash to City Taxes	-33.9	-37.2	-39.5	-43.5
Cash to All Other Purposes	-15.4	0.8	-9.5	-9.8
Cash to Debt Service	-144.8	-150.7	-159.4	-171.0
Cash from Operations	**-$4.8**	**$54.0**	**$62.5**	**$83.6**
Cash from Contributions	25.0	29.7	30.7	33.8
Cash from Bond Proceeds	196.2	176.3	148.7	160.3
Cash to Capital, Conservation and Deferred O&M	**$216.4**	**$260.1**	**$242.0**	**$277.7**

During the 2010 rate-setting process, City Light anticipates that the City Council will pass a resolution revising the existing financial policies as part of its strategy to spread the increase in revenue requirements gradually over 2010-2012. In 2005, Resolution 30761 established the following financial policies for City Light, which determined the Revenue Requirements used to set rates for 2007-2008: 2.0 coverage of all first and second lien debt service, 95% confidence of having $1 or more operating revenue available for capital expenditures, a minimum month-end operating cash balance of $30 million, and a $25 million contingency reserve. It also established a goal of reducing the Department's debt-to-capitalization ratio to 60% by the end of 2010. City Light is proposing the following changes to its financial policies: reduce debt service coverage targets to 1.6 in 2010, 1.7 in 2011, and 1.8 in 2012 and thereafter, in combination with an automatic Power Revenue Adjustment Mechanism (PRAM) described below, no targeted confidence level for operating revenue available for capital expenditures, and a 60% debt-to-capitalization goal that is attained in 2012 rather than in 2010.

It is clear that there are arithmetic relationships among the Department's cash transactions, outlined in Table 1, above. In order to understand the determination of the Department's revenue requirement relative to the other elements of Table 1, it is instructive to examine those relationships explicitly. They are presented in Appendix 8. The first item of Table 1, Retail

Revenue before Rate Discounts, is the Department's revenue requirement and is the subject or target of this report. The elements in Table 1 can be grouped into six specific categories (from the top down). It will become clear that the Department's revenue requirement is affected and controlled by some, but not all, of the categories and specific elements in that table. Additionally, it is possible to show the importance of the financial policy's desired debt service coverage in affecting the revenue requirement. Appendix 8 develops this overview of the relationships of the elements of the cash flow table combined with the debt service coverage ratio.

As part of its proposed changes to its financial policies City Light is also proposing, and anticipating passage of, an ordinance allowing the Utility to establish a mechanism to periodically pass through to customers the financial risk associated with volatility in revenue from wholesale power transactions. This Power Revenue Adjustment Mechanism (PRAM) will increase the revenue certainty of the Utility by adding a charge to customer energy rates when wholesale revenue is below the planned level and reducing customer energy rates when wholesale revenue is higher than planned. By reducing the volatility of City Light's revenue, the PRAM allows City Light to modify its financial policies as described above. This, in turn, will allow the Department to reduce the size of rate increases compared to what they would be under the existing financial policies. However, while customer base rates will be lower with the PRAM, the total rates billed to customers have the potential to be somewhat less stable than under the current financial policies.

City Light's financial policy targets and their level of expected achievement for the 2010-2012 period are displayed in Table 2. Table 2 also displays other key financial indicators.

Table 2

Financial Policy Targets and Key Financial Indicators
(All Dollar Figures in Millions Except Where Noted)

	2009	2010	2011	2012	Target
Debt Service Coverage - Current Year	1.31	1.60	1.70	1.80	√
Debt Service Coverage - Average for ThreeYears	1.75	1.65	1.54	1.70	
M$ Net Income	$36.8	$78.4	$94.5	$104.6	
M$ Year-End Balance in Operating Cash Account	$28.1	$50.1	$99.6	$50.0	√
M$ Year-End Balance in Contingency Reserve Account	$25.0	$25.0	$25.0	$25.0	√
M$ Year-End Balance of Accumulated Net Income	$830.9	$909.3	$1,003.7	$1,108.3	
M$ Year-End Balance of Debt Outstanding	$1,383.1	$1,502.3	$1,622.6	$1,649.6	
Debt as a Percent of Total Capitalization	62%	62%	62%	60%	√
$ per MWh of Wholesale Power	$34.6	$39.4	$44.8	$44.5	
$ per MMBTU of Natural Gas	$3.50	$5.34	$6.31	$6.61	

S.2.1 Changes in Rates and Revenue Requirements in 2010-2012

Table 3 displays the changes in rates billed to retail customers, before low-income discounts, required to produce the cash flows displayed in Table 1 to meet the financial policy targets displayed in Table 2. In addition to the change in average system rates on January 1 of each year, this table shows the amount of BPA costs passed through to customers on October 1 of each year. The BPA pass-through is added onto the "Average System Rate after Rate Change" amount for that year and the combined total is the basis for the "Annual System Rate before Rate Change" on January 1 of the following year.[1]

As an example, the average annual system rate in 2009 before the BPA Pass Through in October of 2009 was $56.47/MWh. BPA changed their rates effective October 2009, and the BPA Pass Through Ordinance required that retail rates be increased by $1.00/MWh to compensate for those BPA rate changes. This increase amounted to 1.8% (1.00 / 56.47). System rates, therefore, increase to $57.47/MWh which is the rate in January 2010 before a rate change.

The average system rate, starting in January 2010, after the rate change, required to satisfy the revenue requirement of $587,762,800 that year is then computed with the assistance of forecasts of retail sales and knowledge of the next BPA Pass Through. Total sales in 2010 are estimated to be 9,387,587 MWh and sales in the last quarter of the year when the 2010 BPA $0.30/MWh Pass Through comes into effect are 2,475,823 MWh. The average system rate after the rate change is then solved for as the (Revenue Requirement – BPA Pass Through*Sales in 4th quarter) divided by total sales for the year.[2] Hence, the **average system rate for 2010** is

(587,762,800 – 0.3 * 2,475,823) / 9,387,587 = **$62.53**

This average rate is an increase of $5.06 (= $62.53-$57.47) over the rate before the change ($57.47) which equates to 8.8% for the average system change.

$5.06 / $57.47 = 0.088 = **8.8%**

Solutions for average system rates after rate change and percentage change in average system rates for the other years are determined in the same manner.

Since residential customers are often more interested in knowing the bill impacts of rate changes than the rate impacts, Table 3 also displays the effect of rate changes on the average monthly residential bill.

Figure 1 presents changes in rates in a historical context, showing that although they are projected to increase over the next three years, these increases are moderate when adjusted for inflation and follow seven consecutive years of declining real electric rates charged by City Light.

---

[1] The BPA Pass Through is controlled by SMC 21.49.081 Automatic BPA cost adjustment.
"Each time that BPA adjusts its rates from those in its block and slice power sales agreements (PSAs) with City Light effective as of January 1, 2007, City Light will calculate the difference (in dollars) between what City Light would have paid for its BPA purchases under the PSAs for a twelve (12) month period beginning on the effective date of the BPA adjustment and what City Light will actually pay for the same period under the adjusted BPA rates. The dollar difference will then be multiplied by 1.1095, which is the effective tax rate, and the product divided by forecast load (in kWh) over the twelve (12) month period to calculate a number (in dollars/kWh rounded to the nearest ten thousandth of a dollar) which will be called the "BPA increment."" In August 2009 BPA announced rate changes for two years effective October 1 in the years 2009 and 2010, and BPA is expected to announce another rate change effective October 1, 2011,which is anticipated to show an increase equal to inflation. Applying the required process to these rate changes, and converting the result to $/MWh, produces BPA Pass Through adjustments on those dates of $1.00, $0.30 and $0.70 per MWh, respectively.

[2] This formula is derived from the requirement that the annual revenue requirement must equal the new rate multiplied by all sales in the year plus the increment in retail revenue associated with the next BPA Pass Through charge. This latter equals the BPA Pass Through charge multiplied by sales in the 4th quarter.

Table 3

Changes in Average Rates and Monthly Bills

	2009	2010	2011	2012
Month of Rate Change		Jan	Jan	Jan
Average Annual System Rate before Rate Change ($ per MWh)	$56.47	$57.47	$62.83	$66.92
Average Annual System Rate after Rate Change	$56.47	$62.53	$66.22	$71.33
Dollar Change in Average Annual System Rate	$0.00	$5.06	$3.38	$4.42
Percent Change in Average Annual System Rate	0.0%	8.8%	5.4%	6.6%
Average Residential Monthly Bill before Rate Change ($)	$43.90	$44.68	$48.85	$52.02
Average Residential Monthly Bill after Rate Change	$43.90	$48.62	$51.48	$55.46
Dollar Change in Average Residential Monthly Bill	$0.00	$3.93	$2.63	$3.43
Percent Change in Average Residential Monthly Bill	0.0%	8.8%	5.4%	6.6%
BPA Pass Through Effective Oct 1 ($ per MWh)	$1.00	$0.30	$0.70	$0.00
Percent Increase in Average Annual System Rate	1.8%	0.5%	1.1%	0.0%

Figure 1

SCL Average Retail Revenue per MWh ($/MWh) 1996-2012

In Actual and Constant 2008 $

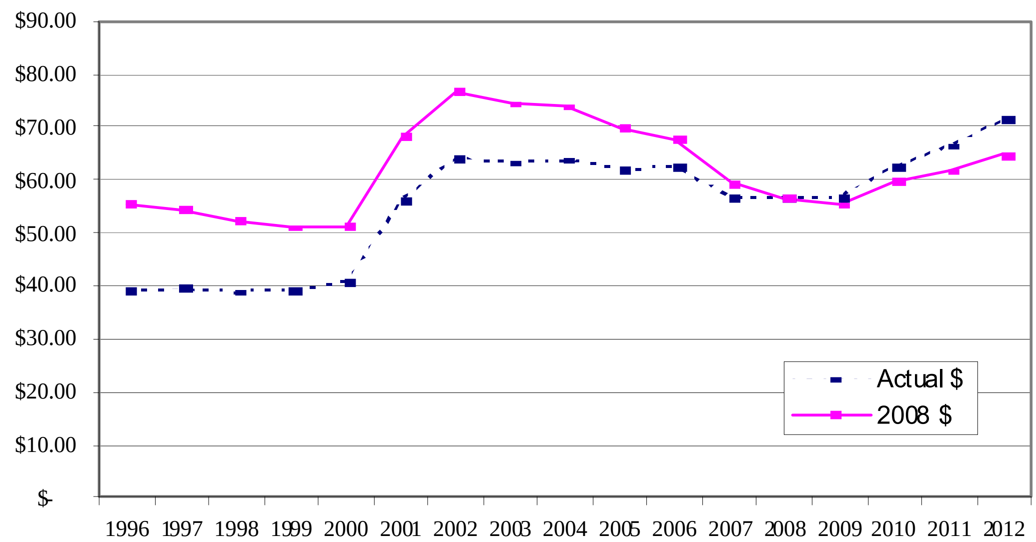


Table 4 compares elements of the current projected revenue requirements in 2010 with revenue requirements in the forecast used to set rates for 2007-2008. Cash to or for various purposes carries a positive sign and cash from various sources carries a negative sign. The difference between these elements of the revenue requirements is in the Gap $ column. The difference is divided by the projected retail load in 2010, of 9,387,587 MWh, to show the effect of each change in terms of $/MWh. The % Change column compares the $/MWh result to the average system rate in 2010 before the rate change associated with the new revenue requirement. This amount is $57.47, shown in Table 3. The sum of all the lower elements in Table 4 equals results shown in the top row of that table.

Reasons for the increase in these requirements include lower wholesale revenue, lower retail load, higher expenditures for certain power contracts, growth in operating expenditures for existing programs due to inflation and above-inflation increases in certain labor and non-labor costs, and new expenditures for programs approved in budgets after the 2007-2008 rates were set.

Table 4

Change in Revenue Requirements from 2007-2008 Rate Forecast to Current 2010 Forecast
(All Dollar Figures in Millions)

	2007-2008	2010	Gap $	$ per Mwh	% Change
Cash from Rate Changes Implemented on Jan 1, 2010	0.0	47.5	47.5	5.06	8.8%
equals					
Cash from Rate Changes Implemented after Jan 1, 2010	0.0	-0.7	-0.7	-0.08	-0.1%
Cash from Rate Changes Implemented before Jan 1, 2010 not in the Average Annual Rate Planned in the Rate Study for 2007-2008	0.0	-11.4	-11.4	-1.22	-2.1%
Cash from Retail Power Sales before Discounts at the Average Annual Rate Planned in the Rate Study for 2007-2008	-539.3	-528.1	11.2	1.19	2.1%
Cash from Wholesale Power Sales, Net	-169.7	-120.0	49.7	5.30	9.2%
Cash from All Other Sources	-56.6	-70.2	-13.6	-1.45	-2.5%
Cash to Power Contracts	276.0	293.4	17.4	1.86	3.2%
Cash to Operations	153.5	201.7	48.3	5.14	8.9%
Cash to Rate Discounts	5.6	6.1	0.5	0.06	0.1%
Cash to Uncollectable Revenue	5.4	5.3	-0.1	-0.01	0.0%
Cash to State Taxes and Franchise Payments	28.2	30.3	2.2	0.23	0.4%
Cash to Debt Service Coverage	297.1	241.1	-56.0	-5.96	-10.4%

The components of Table 4 are explained in more detail below.

S.2.2 Cash from Retail Power Sales before Discounts

The $587.8 million 2010 Retail Power Sales Before Discounts displayed in Table 1 is equal to sum of the absolute values of the top row and the next three rows of the 2010 column in Table 4:

- The Table 4 sum of Cash from Rate Changes Implemented on January 1, 2010;
- Cash from Rate Changes Implemented after January 1, 2010;
- Cash from Rate Changes Implemented before January 1, 2010 not in the Average Annual Rate Planned in the Last Rate Study for 2007-2008;

- and Cash from Retail Power Sales before Discounts at the Average Annual Rate Planned in the Last Rate Study for 2007-2008.

The $47.5 million increase in Cash from Rate Changes Implemented on January 1, 2010, represents the amount that must be collected by increasing the system average rate from the average rate that was set during the 2007-2008 rate process. This increase reflects the net effect of elements that increase and decrease the total change in revenue requirements.

Cash from Rate Changes Implemented after January 1, 2010 and Cash from Rate Changes Implemented before January 1, 2010 not in the Average Annual Rate Planned in the Last Rate Study for 2007-2008 comprise a number of things, including BPA Pass-Throughs in October 2009 and October 2010 that increase average system rates billed to customers by $10.1 million in 2010. The existence of the BPA Pass Through lowers the amount of the revenue requirement that must be collected from further adjusted rates that are computed here. The BPA Pass Through is a mechanism, approved by City Council Ordinance 122282, enabling City Light to pass through to retail customers any changes in amounts charged by BPA arising from changes in BPA's rate schedules.

Cash from Rate Changes Implemented before January 1, 2010 not in the Average Annual Rate Planned in the Last Rate Study for 2007-2008 also reflects changes in customer load profile, suburban city rate increases per franchise agreements, and other patterns of use affecting retail revenue since 2007-2008, which allow City Light to collect slightly more revenue than originally anticipated even without additional change in the rate schedules. Those changes also lower the amount of additional revenue required from further increases to retail rates.

Cash from Retail Power Sales before Discounts at the Average Annual Rate Planned in the Last Rate Study for 2007-2008 is the amount that would be billed to retail customers in 2010 assuming no change in current rates. It is $11.2 million lower than projected 2007-2008 retail revenue because of reductions in retail load, which increases the amount of revenue that must be collected from new retail rates.

S.2.3 Cash from Wholesale Power Sales, Net

Table 1 shows that Wholesale Power Sales Net of Purchases are projected to increase from $69.2 million in 2009 to $120.0 million in 2010, a year-to-year increase of $50.8 million. Table 4 shows that this projection of $120.0 million in wholesale revenue in 2010 is $49.7 million lower than the amount projected for 2007-2008 in the previous rate-setting process. This is the largest single component of the gap to be filled by increasing retail rates in 2010.

The forecast used to set rates in 2007-2008 assumed that 3.4 million MWh of surplus energy would be available for sale, net of purchases in 2007, and 3.2 million MWh in 2008, at an average sales price of $56.14/MWh in 2007 and $47.75/MWh in 2008. The current forecast for 2010 of 3.0 million MWh of surplus energy reflects improvements in our hydroelectric forecasting methodology which reduced overall hydroelectric generation estimates. The 2010 average sales price of $40.17/MWh reflects a natural gas price of $5.34 per MMBtu which is nearly 30% lower than the $7-$8 per MMBtu assumed in the 2007-2008 forecast.

S.2.4 Cash from All Other Sources

Cash from all other sources is projected to total $70.2 million in 2010, a $2.5 million decline from $72.7 million in 2009, shown in Table 1, but $13.6 million higher than the amount projected in the 2007-2008 rate forecast, displayed in Table 4 (recall that sources of cash carry a negative sign). Cash from power contracts increased $6.8 million from the amounts projected to set 2007-2008 rates. Most of this increase is attributable to $6.0 million in anticipated credits from BPA, a reimbursement for the amount City Light overpaid into the BPA Residential Exchange program fund. In 2007, a court ruling found that the program was overcharging publicly owned utilities. City Light began receiving its refund payments in 2008 and it is expected that these payments will continue through September 2015.

Cash from power marketing activities projected for 2010 is $2.0 million higher than the amount assumed in the 2007-2008 rate study. Reasons for the increase include more revenue from basis trades, capacity sales and green tag sales. In addition, cash from the sale of other renewable energy credits, billable operating and maintenance work, reimbursement for work on cell sites, and revenue from curbing energy losses caused by current diversion and unpermitted house rewires is projected to be $4.8 million greater than the amount projected for 2007-2008.

Sales of surplus property are $4.3 million lower in the current 2010 forecast than those projected in the forecast used to set rates in 2007-2008. The sale of an $8.5 million property in South Lake Union had been projected to occur in 2007 but has been delayed for several years and removed from the forecast until it becomes more certain. Investment income is $1.5 million below the average amount in the 2007-2008 revenue requirements forecast because of lower interest-earning balances and lower interest rates.

S.2.5 Cash to Power Contracts

Cash to power contracts projected for 2010 is $17.4 million higher than the average amount projected to set rates in 2007-2008. Expenditures for Priest Rapids power purchases increased the most, rising $10.8 million, due to new contract terms. This is followed by wheeling charges, up $8.4 million, and water for power expenses, up $6.1 million because of increases in FERC administrative fees and land rent charges. Sierra Pacific Industries and Columbia Ridge, resources that have been added to the forecast since 2007-2008 rates were set, jointly increased cash to power contracts by $4.5 million in 2010. These increases, and a variety of smaller ones, were partially offset by a $7.9 million reduction in expenditures for Lucky Peak, which has become a less expensive resource now that its debt has been completely paid off, and a $6.5 million decrease in BPA purchases.

S.2.6 Cash to Operations

Cash to operations projected for 2010 is $48.3 million higher than the average amount projected to set rates in 2007-2008. Cash to operations is a sum of cash spent on production, transmission, distribution, conservation, customer accounting and administration.

Cash to production is $10.5 million higher. Key reasons include increased staffing and space rentals to support construction management, power marketing, risk management, settlements and new resource acquisition functions. Also included are maintenance projects at Skagit and Boundary as required by federal standards and regulations, as well as expenditures to meet FERC requirements for relicensing the Boundary Project in 2011, the Climate Program and purchases of greenhouse gas offsets.

Cash to transmission is $3.3 million higher. This increase primarily reflects rising labor and materials costs for ongoing maintenance of transmission property and equipment. It also includes increased expenditures for security and safety.

Cash to distribution is $10.1 million higher. Rising labor costs are a major contributor to this increase. Specific planned expenditures in 2010 that also contribute to this increase include streetlight re-lamping, pole testing and treatment, reimbursable cell site and pole attachment construction, feeder maintenance, vegetation management, the apprenticeship program, planning and training mandated by the National Electricity Reliability Council (NERC) to improve reliability, security services, a crane safety program, and asset management and work management programs.

Cash to conservation is $6.3 million higher. This increase mainly represents staffing required to plan, administer and evaluate City Light's "Conservation Five Year Action Plan," although this program has been scaled back a little since originally proposed in 2008. The plan aims to significantly expand City Light's energy conservation acquisitions in 2008-2012.

Cash to customer accounting is $5.3 million higher. Higher labor costs are a significant component of this increase, particularly expenditures for meter reading and customer assistance. It also includes increased expenditures for an expanded Call Center.

Cash to administration is $12.7 million higher. Like several previous line items, this increase also reflects significant growth in labor costs. Other major contributing factors are growth in payments for toxic cleanup at the Duwamish Superfund site, space leases and rentals, IT expenditures, the apprenticeship program, a variety of human resources training programs including safety training, training mandated by the Mayor's office to promote equal opportunity and prevent workplace violence and sexual harassment, and low income assistance programs (excluding rate discounts).

S.2.7 Cash to Rate Discounts

Cash to rate discounts projected for 2010 is $0.5 million above the average level projected to set rates in 2007-2008. Residential customers that qualify for City Light's low-income rate discount program pay rates that are 40% of standard residential rates. This discount is available to customers who receive Supplemental Security Income and households with incomes less than 70% of the Washington State median income. Since standard rates are projected to increase in 2010, this 60% discount offered to low-income customers is projected to increase proportionately.

S.2.8 Cash to Uncollectable Revenue

Cash to uncollectable revenue is $0.1 million lower than the average amount projected to set rates in 2007-2008. This mainly reflects improvements in City Light's collection processes, reducing the amount of revenue that must be written off as uncollectable. The forecast used to set rates in 2007-2008 assumed that the percent of retail energy sales that would not be collectable would be 1.1% in 2007, dropping to 0.9% in 2008 and later years because of improved collections. The current forecast for 2010 assumes it will be 0.9%.

S.2.9 Cash to State Taxes and Franchise Payments

Cash to state taxes, franchise payments, and contractual payments to local governments in lieu of taxes are projected to be $2.2 million higher than the average 2007-2008 amount projected in the previous rate-setting process. Most of the increase is in state tax payments, which are $1.5 million higher because of higher retail revenue from new rates. Franchise payments are up $0.5 million and in-lieu-of-tax payments to local governments are up $0.1 million.

S.2.10 Cash to Debt Service Coverage

Cash to debt service coverage projected for 2010 is $56.0 million lower than the average amount used to set rates in 2007-2008. There are two key reasons for this: a lower target debt service coverage ratio and a very small increase in the amount of debt service to be covered. As mentioned above, City Light anticipates that its financial policies will be revised by City Council during the current rate setting process, allowing the debt service coverage ratio target to be reduced from 2.0 times all first and second lien debt service to 1.6 in 2010, 1.7 in 2011 and 1.8 in 2012. The reduction of this target from 2.0 to 1.6 in 2010 reduces the amount of cash required to meet it by $60.3 million. The amount of debt service to be covered in 2010 is only slightly above the average amount projected during the 2007-2008 rate-setting process because no new debt is projected to be issued during 2009. The next debt issuance, which is projected to be $200 million, is expected to occur in March 2010, and no interest or principal payments will be made on that debt until 2011. This delay reduces debt service in 2010 by $4.8 million and reduces the amount of cash required to cover it 1.6 times by $7.7 million.

S.2.11 Bridging the Gap: Management Decisions Taken to Reduce the Size of the 2010 Rate Increase

During the current rate-setting process, City Light management has made a series of decisions aimed at moderating the size of the rate increase to be implemented on January 1, 2010, to keep it at a level acceptable to City Light ratepayers during an economically challenging time. The $47.5 million Cash from Rate Changes Implemented on January 1, 2010, which is displayed in Table 4, is $94.2 million less than the $141.7 million that would have been required without these decisions. Table 5 displays the components of the $141.7 million that would have been required and the associated rate impacts in dollars per MWh and in percentage increases. Table 6 displays the differences between components of the $141.7 million and components of the currently proposed $47.5 million increase in revenue requirements. This last table shows that the three main contributors to the reduction in proposed 2010 revenue requirements are a $6.6 million increase in cash from other sources, a $12.7 million decrease in cash to operations and a $69.9 million decrease in cash to debt service coverage. These changes directly reflect management decisions. The smaller changes in cash to rate discounts (down $1.0 million), cash to uncollectable revenue (down $0.8 million), and cash to state taxes and franchise payments (down $3.1 million) are indirect effects resulting from the lower amount of new retail revenue required by the current rate proposal.

Tables 5 and 6 are constructed and interpreted in a manner similar to Table 4.

Table 5

Change in Revenue Requirements from 2007-2008 Rate Forecast to Current 2010 Forecast before Decisions

(All Dollar Figures in Millions)

	2007-2008	2010	Gap $	$ per Mwh	% Change
Cash from Rate Changes Implemented on Jan 1, 2010	0.0	141.7	141.7	15.09	26.3%
equals					
Cash from Rate Changes Implemented after Jan 1, 2010	0.0	-0.7	-0.7	-0.08	-0.1%
Cash from Rate Changes Implemented before Jan 1, 2010 not in the Average Annual Rate Planned in the Rate Study for 2007-2008	0.0	-11.4	-11.4	-1.22	-2.1%
Cash from Retail Power Sales before Discounts at the Average Annual Rate Planned in the Rate Study for 2007-2008	-539.3	-528.1	11.2	1.19	2.1%
Cash from Wholesale Power Sales, Net	-169.7	-120.0	49.7	5.30	9.2%
Cash from All Other Sources	-56.6	-63.6	-7.0	-0.75	-1.3%
Cash to Power Contracts	276.0	293.4	17.4	1.86	3.2%
Cash to Operations	153.5	214.4	61.0	6.49	11.3%
Cash to Rate Discounts	5.6	7.1	1.5	0.16	0.3%
Cash to Uncollectable Revenue	5.4	6.1	0.7	0.08	0.1%
Cash to State Taxes and Franchise Payments	28.2	33.5	5.3	0.57	1.0%
Cash to Debt Service Coverage	297.1	311.1	14.0	1.49	2.6%

Table 6

Change in Revenue Requirements from 2007-2008 Rate Forecast to Current 2010 Forecast from Decisions
(All Dollar Figures in Millions)

	2007-2008	2010	Gap $	$ per Mwh	% Change
Cash from Rate Changes Implemented on Jan 1, 2010	0.0	-94.2	-94.2	-10.03	-17.5%
equals					
Cash from Rate Changes Implemented after Jan 1, 2010	0.0	0.0	0.0	0.00	0.0%
Cash from Rate Changes Implemented before Jan 1, 2010 not in the Average Annual Rate Planned in the Rate Study for 2007-2008	0.0	0.0	0.0	0.00	0.0%
Cash from Retail Power Sales before Discounts at the Average Annual Rate Planned in the Rate Study for 2007-2008	0.0	0.0	0.0	0.00	0.0%
Cash from Wholesale Power Sales, Net	0.0	0.0	0.0	0.00	0.0%
Cash from All Other Sources	0.0	-6.6	-6.6	-0.70	-1.2%
Cash to Power Contracts	0.0	0.0	0.0	0.00	0.0%
Cash to Operations	0.0	-12.7	-12.7	-1.35	-2.4%
Cash to Rate Discounts	0.0	-1.0	-1.0	-0.10	-0.2%
Cash to Uncollectable Revenue	0.0	-0.8	-0.8	-0.09	-0.2%
Cash to State Taxes and Franchise Payments	0.0	-3.1	-3.1	-0.33	-0.6%
Cash to Debt Service Coverage	0.0	-69.9	-69.9	-7.45	-13.0%

The major components of Table 6 are explained in more detail below.

S.3 Increase in Cash from All Other Sources

The $6.6 million increase in cash from all other sources is based on executive decisions made by management. The largest contributors include renewable energy credits, billable operating and maintenance work, reimbursement for work on cell sites, and revenue from curbing energy losses caused by current diversion and unpermitted house rewires. Additions of $7.0 million from these sources are partially offset by a $0.4 million decrease in investment income. The list of these additional sources of revenue is included in Appendix 5.

S.4 Decrease in Cash to Operations

Prior to the decisions taken by City Light management during the current rate-setting process, the amount of new revenue required to cover cash to operations would have increased by $61.0 million, as shown in Appendix 6. In the current rate proposal, new revenue required to cover cash to operations totals $48.3 million, which is $12.7 million less than the original amount before management decisions to reduce these expenditures were taken. This $12.7 million is a net number that includes $11.3 million of additional operating expenditures agreed to by management minus $24.0 million in expenditure reductions. The reasons for the increases in cash to operations are described above in Section S.2.6. The list of these increases as well as a list of the reductions is included in Appendix 5.

S.5 Decrease in Cash to Debt Service Coverage

The amount of revenue required from new rates in 2010 for cash to debt service coverage is $69.9 million lower than the amount that would have been required. As described in Section S.2.10, this reduction results primarily from the proposal to revise the financial policy for debt service coverage from 2.0 to 1.6 and secondarily from the decision to delay new debt issuance from October 2009 to March 2010, and delay interest payments on that debt issue until 2011.

Chapter 1 - Cash from Retail Power Sales before Discounts

Cash from Retail Power Sales before Discounts for 2010 is the subject of this *RRA* and is the cash that the Department will receive from

- Energy Charges ($ per kWh) applied to the energy used by Retail Customers
- Capacity Charges ($ per kW) applied to the capacity used by Retail Customers
- Base Service Charges ($ per day) applied to the number of Residential Retail Customers.

Cash from Retail Power Sales before Discounts is the amount of operating cash required, in addition to operating cash from wholesale power sales and all other sources, to cover expenses and meet financial targets specified in the Department's financial policies. The total of this item for 2010 is $587.8 million (see Table 1 in the Summary chapter and Table 1.1 in this chapter) and is the revenue requirement for that year. This amount equals $5.06 per MWh and is the Base Rate Change proposed to be effective January 1, 2010. The guiding financial policies that, in conjunction with forecasts of the other revenue sources and expected expenses, lead to this conclusion are briefly described in Section S.2 of the Summary chapter and presented in more detail in Appendix 3.

This cash flow is before discounts given to Low Income customers. See Chapter 6 for more detail about the Low Income Assistance Program.

Retail charges are differentiated by service area and by rate class. The service areas served by Seattle City Light are:

- City of Seattle Downtown Network
- City of Seattle Outside of the Downtown Network
- City of Tukwila
- City of Shoreline
- City of Burien
- Suburban Areas Outside of Seattle, Tukwila, Shoreline, and Burien

The rate classes recognized by Seattle City Light are:

- Residential Service (Regular)
- Residential Service (Assisted)
- Small General Service
- Medium General Service
- Large General Service
- High Demand General Service
- Street and Flood Lights

City Light maintains a revenue file with monthly historical and forecasted values for energy used, capacity used, and customer counts by service area and rate class for years 1990 to 2021.

For forecast years, these quantities are applied to the retail charges entered or calculated for these years to arrive at the forecast of Cash from Retail Power Sales before Discounts.

The dollar value of Cash from Retail Power Sales listed for any given year is the cash that will be received from energy used, capacity used and customer charges that year. Meters are read after the energy and capacity are used. Bills are sent out after the meters have been read. The cash comes in after the customers have received and paid their bills. As a result there is a significant lag between the time the cash is earned and the time it is received. Part of the cash earned in one year will be received the next year. Part of the cash received one year will have been earned the prior year. The cash earned in a year is counted as available for debt service coverage that year. The lag in cash flow is accounted for as "Cash to All Other Purposes" in the calculation of "Cash from Operations".

Table 1.1 shows the Cash from Retail Power Sales before Discounts, Energy Delivered to Retail Customers and Average Cash Received per MWh Delivered in total and for each Rate Class, as well as Cash to Rate Discounts and Cash from Residential Service (Assisted) after Discounts.

The values shown for 2007-2008 are the average values forecasted for these two years in the 2007-2008 Rate Study. The 2007-2008 base values in this table, therefore, are not the values used in determining the 8.8 percent increase in the average system rate. As explained above and in the Summary chapter, the 8.8 percent increase is an increase over rates in existence just prior to incorporation of the effect of the 2010 revenue requirement.

In general, most of the discussion in the remainder of this *RRA* compares the proposed 2010 results with the annual average values for those two years in the 2007-2008 Rate Study. These comparisons are useful in explaining changes since the last rate case, but they differ from the information, provided in the Summary, needed to explain the immediate effect of the 2010 revenue requirements on currently existing rates.

The values shown for 2010 in Table 1.1 are from the current Rate Study. The values for 2010 include all of the rate changes which have been made or are scheduled to be made before the end of 2010. These[3] include:

- $1.00 per MWh BPA Pass Through effective October 1, 2009 (1.8% increase)
- $5.06 per MWh Base Rate Change effective January 1, 2010 (8.8% increase)
- $0.30 per MWh BPA Pass Through effective October 1, 2010 (0.5% increase)

Note that the first and last of these changes are associated with the automatic BPA Pass Through and are not associated with the revenue requirement increase proposed by the Department for its own sake.

The annual average rate for 2010 in Table 1.1 is $62.61 per MWh. This annual average price includes the increase in BPA costs starting October 1, 2010. This is the annual system rate that would be necessary starting January 1 if the BPA cost increases went into effect and there were no automatic pass through. But, because the automatic pass through does exist, and becomes effective in October, the system rate needed to start the year is $62.53, succeeded by an increase

[3] See Table 3 in the Summary chapter for these numbers.

in the rate to $62.83 in October (see Table 3 in the Summary chapter), producing an annual average rate of $62.61.

A few observations can be made about entries in Table 1.1.

Sales to Residential Customers are down about 260,000 MWh or about 8.5%. Sales to Small General Service Customers are down about 40,000 MWh or 3.4%. Sales to other General Service Customers are up about 100,000 MWh or 2.0%. Total Energy Sales are down about 200,000 MWh or 2.1%. The general decline in consumption is directly attributable to the economic downturn confronting the nation and our local area.

Retail charges for low income customers are discounted by 60%. The cash not received as a result of these discounts is considered “Cash to Rate Discounts”. The value of these discounts and the “Cash from Residential Service (Assisted) after Discounts” and the “Residential Service (Assisted) Average Rate after Discounts” are shown on the bottom of Table 1.1.

Table 1.1
Cash from Retail Power Sales before Discounts

	2007-2008	2010	Diff	% Diff
Cash from Retail Power Sales before Discounts (Dollars)	539,306,857	587,762,800	48,455,943	9.0%
Residential Service (Regular)	194,617,166	199,108,761	4,491,595	2.3%
Residential Service (Assisted)	9,258,000	10,239,573	981,573	10.6%
Small General Service	67,473,847	72,448,245	4,974,399	7.4%
Medium General Service	122,845,418	138,841,247	15,995,830	13.0%
Large General Service	80,384,757	90,316,898	9,932,141	12.4%
High Demand General Service	53,242,930	64,739,693	11,496,763	21.6%
Street and Flood Lights	11,484,740	12,068,383	583,643	5.1%
Energy Delivered to Retail Customers (MWh)	9,586,809	9,387,586	(199,223)	-2.1%
Residential Service (Regular)	3,061,023	2,801,515	(259,508)	-8.5%
Residential Service (Assisted)	144,846	142,711	(2,135)	-1.5%
Small General Service	1,215,622	1,174,544	(41,078)	-3.4%
Medium General Service	2,375,325	2,388,381	13,057	0.5%
Large General Service	1,534,402	1,542,401	7,999	0.5%
High Demand General Service	1,160,678	1,243,119	82,442	7.1%
Street and Flood Lights	94,915	94,915	0	0.0%
Average Cash Received per MWh Delivered before Discounts	56.26	62.61	6.36	11.3%
Residential Service (Regular)	63.58	71.07	7.49	11.8%
Residential Service (Assisted)	63.92	71.75	7.83	12.3%
Small General Service	55.51	61.68	6.18	11.1%
Medium General Service	51.72	58.13	6.41	12.4%
Large General Service	52.39	58.56	6.17	11.8%
High Demand General Service	45.87	52.08	6.21	13.5%
Street and Flood Lights	121.00	127.15	6.15	5.1%
Cash to Rate Discounts (Dollars)	5,551,017	6,086,307	535,290	9.6%
Rate Discounts ($/MWh)	38.32	42.65	4.32	11.3%
Rate Discounts (%)	60.0%	59.4%	-0.5%	-0.9%
Cash from Residential Service (Assisted) after Discounts	3,706,983	4,153,266	446,283	12.0%
Residential Service (Assisted) Avg Rate after Discounts	25.59	29.10	3.51	13.7%

Chapter 2 - Cash from Wholesale Power Sales, Net

The forecast of **Cash from Wholesale Power Sales, Net** recognizes the uncertainty in three elements that determine its value. These elements are (1) the energy sales to customers, (2) the energy generated by hydro resources and (3) the wholesale energy market prices. Thus, the forecast of Net Cash from Wholesale Power Sales is represented by a probability distribution. The average value is used in the estimation of the revenue requirement, but the actual value is known to be uncertain and has the potential to vary within certain bounds of the expected value.

The uncertainty in energy sales to customers is important because an increase (decrease) in retail sales will result in a decrease (increase) in the amount of energy that is delivered to the wholesale power market. In the event the Department is buying power from the wholesale market, an increase (decrease) in retail sales will result in an increase (decrease) in power purchased from the market.

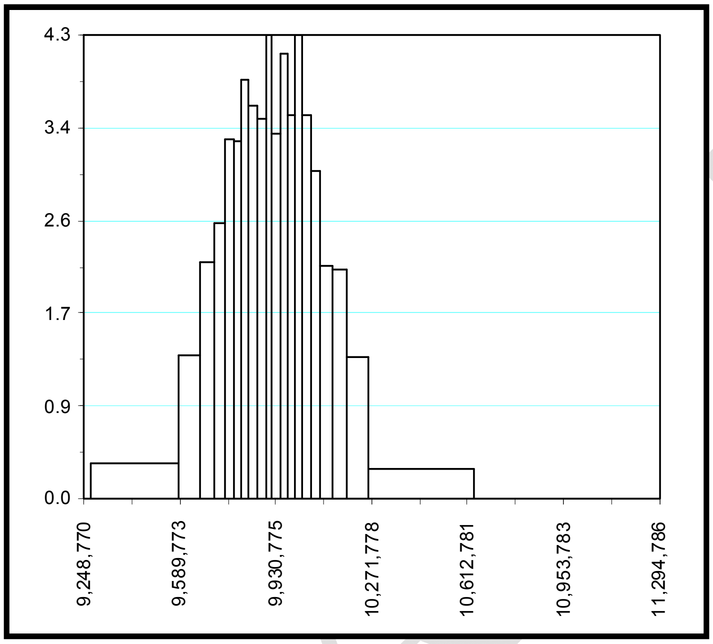
The forecast model assumes ranges of uncertainty around three important components of the forecast of energy sales to customers: base load, load used for heating residences and buildings, and load used for cooling residences and buildings. All of this data is broken out by months and by light load hours and heavy load hours within each month. This breakout is important because of the significant differences in prices for electricity purchased or sold during light load and heavy load hours.

This data is input to a Monte Carlo simulation model that is run 2001 times in order to provide a statistically meaningful sample of scenarios. The annual outputs of this process allow us to estimate the annual average result across all of the scenarios and a probability distribution of annual values over 2000 intervals that reflect the combined effects of all of the uncertainty factors used as inputs to the model, which are further described below.

Figure 2.1 on the next page illustrates the uncertainty of the Seattle system load for 2010. This load is primarily retail sales, but it also includes estimates of output consumed by City Light itself, mostly at its generating facilities, and energy losses in transmitting and distributing energy to its customers. The bottom axis shows various outcomes for the system load in 2010 where the variability is nearly entirely associated with retail sales. The vertical axis is probability density expressed as percents. The results have been scaled so that the sum of the areas of the 20 blocks (or bins) of data equal the length of the bottom axis. This last feature is for cosmetic purposes. The main point is that the figure illustrates that there are a variety of outcomes and the probability of an outcome being in a specific one of the 20 blocks varies with the location on the bottom axis of that block.

The second type of uncertainty is the weather conditions that impact snowpack, streamflows and water stored behind the dams of the hydroelectric generating projects owned by or under contract to the Department. Resource availability will also vary slightly from year to year due to changes in the planned operations for these resources, which include planned outages for maintenance and changes in operating schedules in order to comply with environmental regulations such as federally mandated fish flow requirements.

Figure 2.1
Seattle System Load – Potential MWh Outcomes, 2010



Power resources are taken directly from the outputs of a model called the Hedge Evaluation and Risk Analysis (HERA) model developed and maintained by the Power Management Division. That model generates 2001 resource scenarios corresponding to the 2001 load scenarios described above. Energy generated from City Light's own hydro facilities at Ross, Diablo, Gorge, Boundary, and Cedar Falls as well as energy generated from primarily or exclusively hydro-based resources purchased from BPA Slice, Lucky Peak, and the Grand Coulee Project Hydroelectric Authority ("GCPHA") are considered uncertain. All other resources, for example BPA Block power which is a contract for purchasing a fixed amount of power each month, are set to average contract or expected values for the 24 monthly heavy load and light load time periods of the year.

Figure 2.2 on the next page illustrates the range of potential output from City Light's own resources and its resource contracts. As in the previous figure, the bottom axis is MWh and the vertical axis is probability density expressed in percent terms. Again, the data have been scaled for presentation purposes so that the areas of the 20 blocks of data equal the length of the bottom axis. And as before, the main purpose is to represent the potential variability in output.

Figure 2.3, also on the next page, then illustrates the potential variability of City Light's energy to (from) the wholesale power market. The data exclude transmission losses on power market transactions but the basic message of the variability in net transactions with the power market is clear. City Light has some probability of being a net purchaser, though the probability is quite low, and also a potential for selling five million MWh, or more. In short, there is great variability in what might be sold to the wholesale power market.

Figure 2.2
Potential MWh Output of City Light's Own Resources and Contracts for 2010

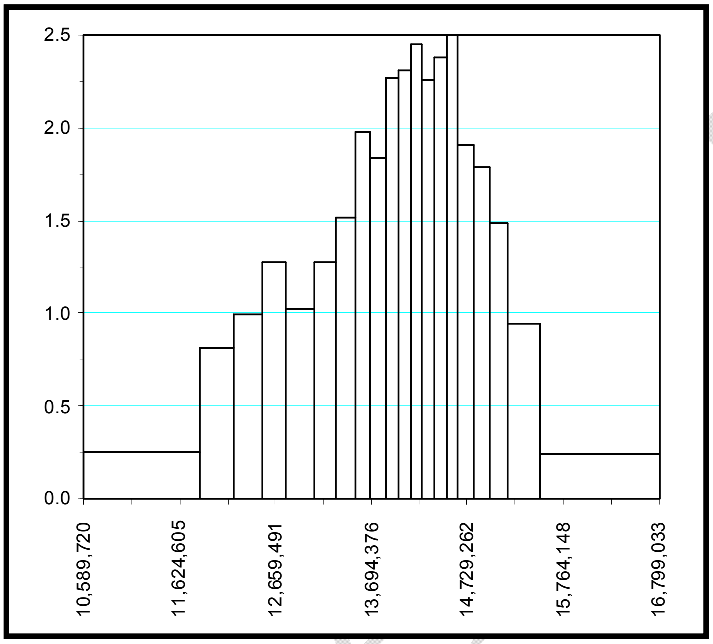
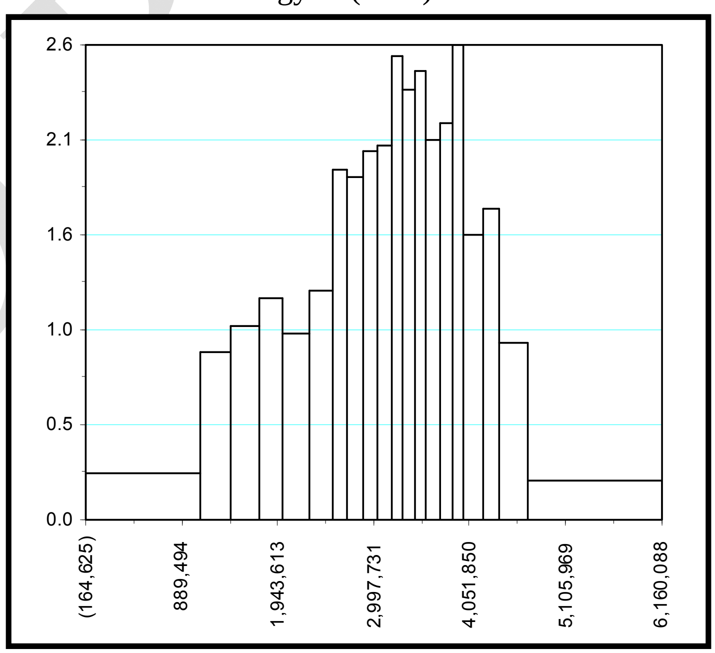


Figure 2.3
Potential MWh of Energy to (from) Power Markets in 2010



The third type of uncertainty is price uncertainty, which is a function of several factors that influence wholesale market prices for electricity in the Pacific Northwest, the most important of which are water conditions and wholesale market prices for natural gas.

Water conditions are negatively correlated with market prices after adjusting for other factors. The more water that is available, the greater the supply of hydro power and, for the given market for power, the lower will be the equilibrium sales price.

Wholesale natural gas prices are important for determining wholesale electricity prices for several reasons. First, the wholesale electricity market on the West Coast is strongly integrated by long distance transmission lines and surplus hydro power can be sold to buyers nearly anywhere in that area. Second, on the West Coast, natural gas-fired combustion turbines are the major electrical generating resource 'on the margin', i.e., available to be called on to dispatch additional energy when there is a sudden change in the demand for electrical energy. Hydro energy, typically, can be dispatched as rapidly, if not more rapidly, than energy from a gas-fired combustion turbine. Thus, hydro power competes with combustion turbines in the wholesale market. Hydro power will not be priced higher than the operating cost of a combustion turbine. By like token, hydro power typically is able to command a price equal to the operating cost of a combustion turbine.

The model to forecast net cash from wholesale power sales is constructed so that a probability distribution of results is created, rather than simply, and only, one point forecast. The model is constructed by combining information about history and certain forecasts. Some historical data are generally considered to reflect stresses occurring in the relevant market or that water conditions were atypical. Hence, in constructing the model, and its various constituent parts, rather than taking data directly from only one source, for example from one time frame, there is an attempt to start with what is considered to be 'representative' data for use as a base. Then, deviations around that base are created based on historical information about the degree of variability observed. Consequently, the model creates a probability distribution that is founded on a 'base' or 'representative' foundation which then spreads higher and lower based on information about the variability inherent in the data.

Expected monthly electric prices by heavy load and light load hours for 2010 were calculated in several steps, relying on the concepts just noted. Data used in the several steps to be described shortly were taken from different time periods, but each was considered 'typical' or 'representative' for that type of information. There was a conscious recognition and decision that no single date would provide 'representative' data for all the types of data that are required.

The first step used the annual average forward market gas price for the forecast year in question as of 8/19/2009 as reported by Platts.[4] That price was then converted to monthly prices by using a reasonable monthly profile. The profile chosen for this purpose was that of the gas prices for 2009 from the forward market on 10/22/2008. The resulting expected monthly gas prices were then multiplied by the 6/24/2009 forward market heat rates (as defined below) for the heavy load

[4] Platts is a division of the McGraw-Hill Companies. Platts is an independent resource delivering forward pricing in the North American electricity market including daily on-peak and off-peak assessment at 17 key electricity trading hubs, extending out four years.

and light load hours of the corresponding month to obtain the expected 2010 electric prices for each of those 24 time periods.[5]

In summary, the basic steps in projecting wholesale electricity prices are: (1) forecast gas prices, (2) forecast market heat rates, (3) multiply the two to get electricity price projections. Each of these steps involves probability distributions as discussed below. The following paragraphs explain more about how these steps work, then some figures are presented to illustrate the uncertainty, or the probability distributions, of the different outcomes.

The City Light forecast of wholesale revenue stochastically forecasts electricity prices by making use of a ratio known to the energy community as the "market heat rate," which is the price of electricity divided by the price of natural gas. The market heat rate typically depends upon the amount of natural gas used to generate electricity.

Gas turbines differ in the amount of natural gas they consume to produce a given quantity of electricity. Gas consumption is calibrated in terms of millions of British Thermal Units (MMBTUs). Electricity, measured for wholesale transactions, is calibrated in terms of megawatt hours (MWh). The most efficient turbines are used first to produce electricity since they cost the least. A heat rate is defined as the efficiency of a gas turbine to produce a given output of electricity. This heat rate is calibrated as the ratio MMBTU / MWh.[6] Note that the larger the heat rate number, the less efficient the gas turbine and the more gas it must consume to produce a unit of electricity. High heat rates are 'bad', while low heat rates are 'good'.

As demand for natural gas used to generate electricity increases, the need to use less efficient gas turbines increases. These less efficient units use even more gas per unit of electricity than the more efficient turbines already in operation; hence, a proportionately greater demand for natural gas occurs. Not surprisingly, the larger the amount of natural gas used, the higher the natural gas price is driven.

The quantity of natural gas used, in turn, is a function of water available for hydro generation and the electrical energy used by Western Electricity Coordinating Council[7] (WECC) customers, which, in turn, depends upon base load, heating load and cooling load, similar to the City Light service area but on a much larger scale.

[5] Further details about developing these estimates of wholesale price uncertainty, or other aspects of the process for estimating net cash from wholesale power sales, are available from the Financial Planning Unit of Seattle City Light.
[6] Note that the ratio of the price of electricity to the price of natural gas has the units:
(\$/MWh) / (\$/MMBTU) = (\$/MWh) * (MMBTU/\$) = (MMBTU/MWh). Thus the term "market heat rate" has the same units as the simple heat rate and, as mentioned, is derived as the ratio of prices of electricity/gas.
[7] From WECC website: http://www.wecc.biz/About/Pages/default.aspx: "WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the vastness and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles."

The market heat rate can fall to very low levels when no natural gas is being used for electrical generation, but it can also reach very high levels when the demand for electricity exceeds the capability of all generation in the WECC area. City Light recognizes the random nature of deviations in the major elements that determine the market heat rate and uses this information to calculate the deviations in the market heat rate from expected values.

City Light calculates market prices for natural gas in a similar manner, by looking at the major elements that cause deviations from its expected values. This calculation recognizes that there is a correlation between the price of natural gas and the amount of natural gas used for electrical generation. For example, as water available for hydro generation in the WECC decreases, the market heat rate goes up, and this in turn drives up the price of natural gas. City Light then uses its forecast of gas prices to calculate electricity prices, by multiplying the price of gas times the market heat rate.

The price of natural gas has significant volatility. Some of the drivers of that volatility are not completely transparent. For example, although we know that hurricanes in the Gulf of Mexico and world oil prices have impacts on gas prices, we are not able to quantify those impacts at this time. Therefore, gas prices should be considered the greatest source of uncertainty in City Light's forecast of wholesale electricity prices.

Figures 2.4 through 2.7 illustrate the historical volatility of three variables considered here. Figure 2.4 illustrates the volatility of natural gas prices. The figure presents data on price of natural gas at the Henry Hub trading center which is used throughout North America as a standard. Prices at other trading hubs are often quoted in terms of the Henry Hub price plus or minus a fixed amount. The main point of the figure is the volatility, which is representative of the volatility at any natural gas trading hub in North America. The figure illustrates the high level of prices that occurred in the energy crisis of 2000-2001, as well as the spikes in 2005 and 2008. However, since mid 2008, natural gas prices have been on a downswing, with the potential of having bottomed out recently.

Figure 2.5 illustrates wholesale electricity prices at the Mid Columbia trading hub. Once again, there was a dramatic surge in prices during the energy crisis of 2000-2001. Indeed, it may appear that prices have been relatively stable since then. That latter appearance, though, is an artifact of the huge price spike in 2000-2001. Figure 2.6 presents Mid Columbia prices subsequent to that time period and illustrates that they remain quite volatile. Figure 2.7 illustrates the market heat rate over a comparable time period. Again, it is clear that there has been significant volatility in this variable even in the recent few years.

Figure 2.4
Natural Gas Prices

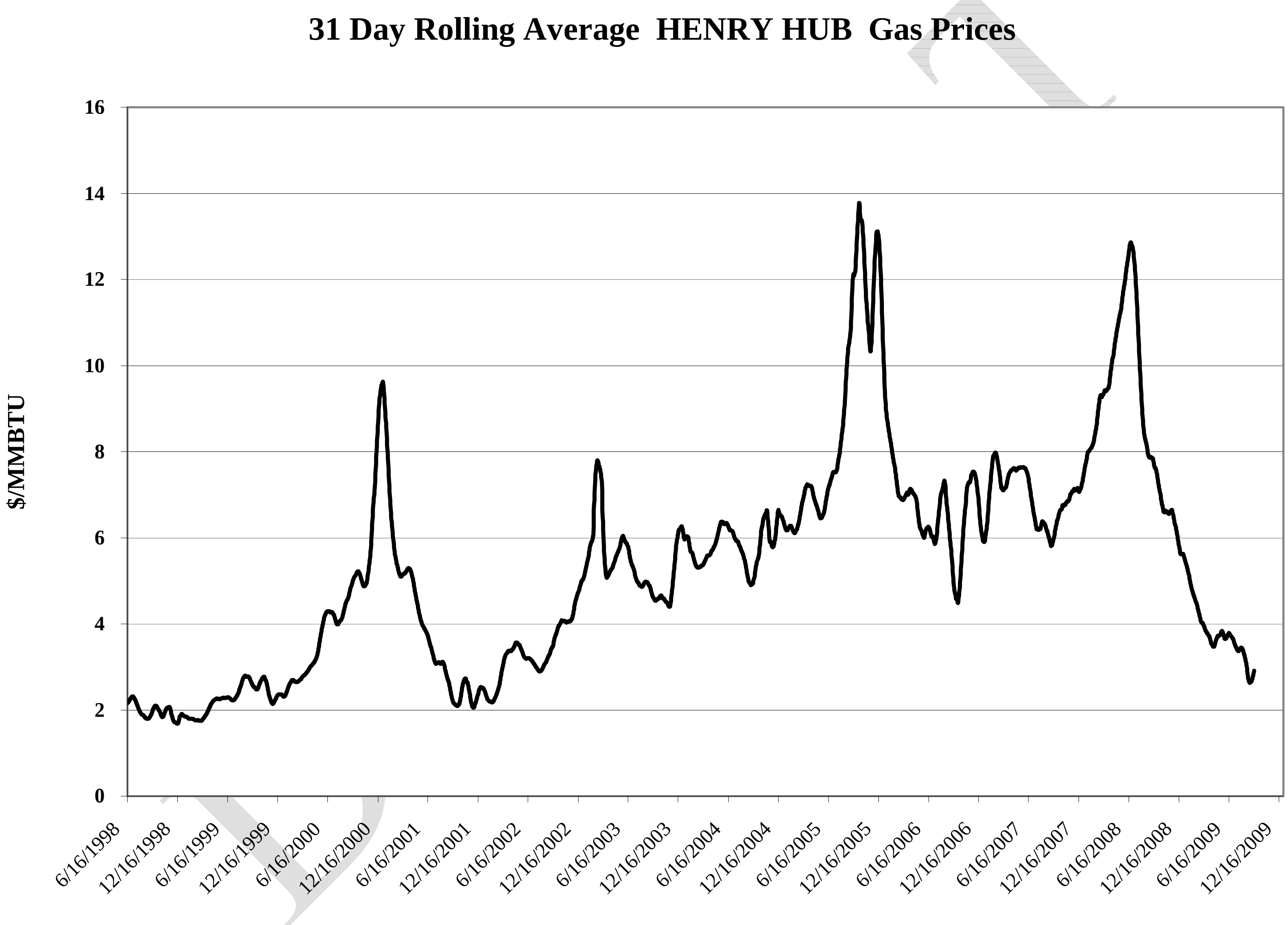


Figure 2.5
Long-Term Wholesale Electricity Prices

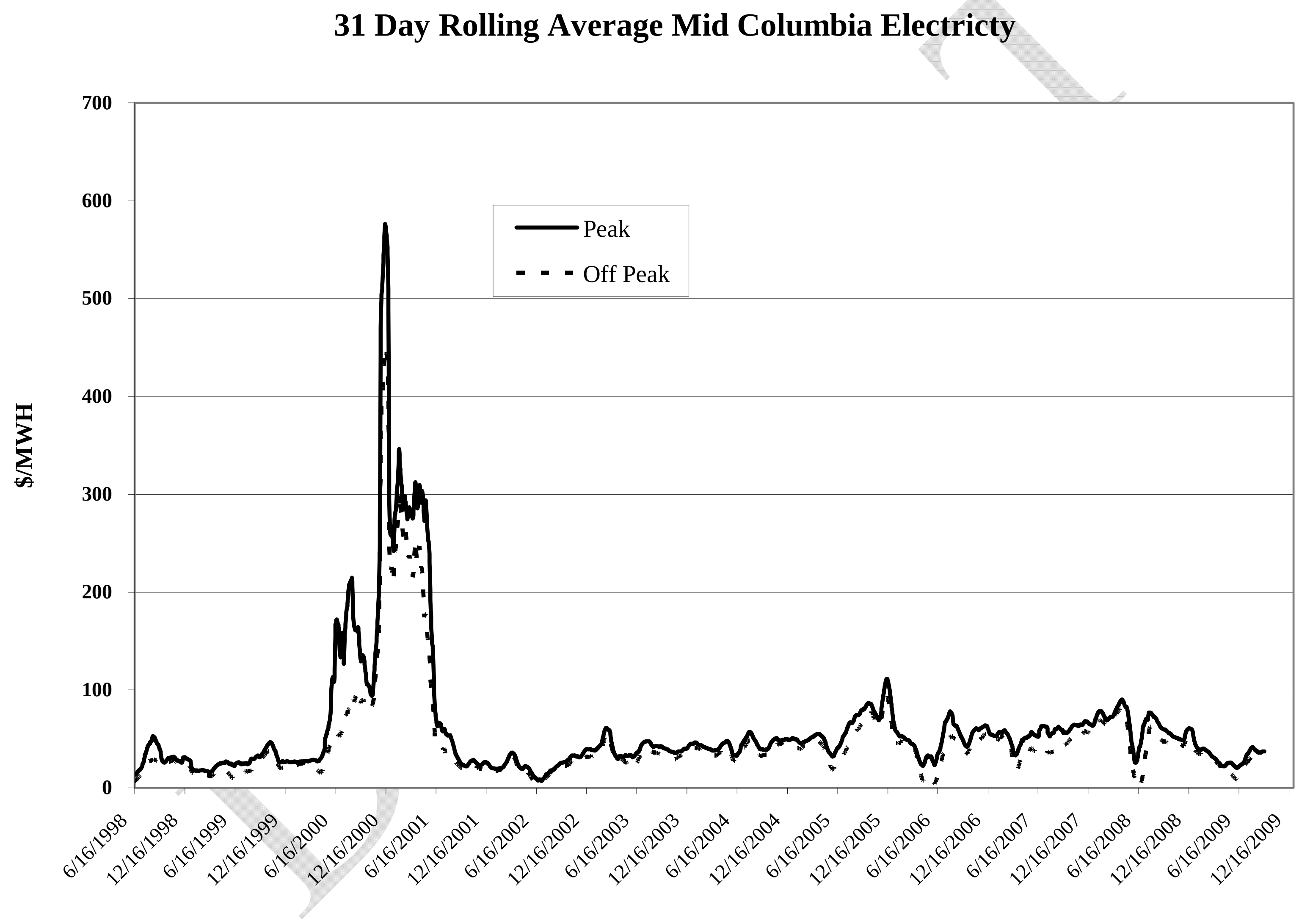


Figure 2.6
Mid-Term Wholesale Electricity Prices

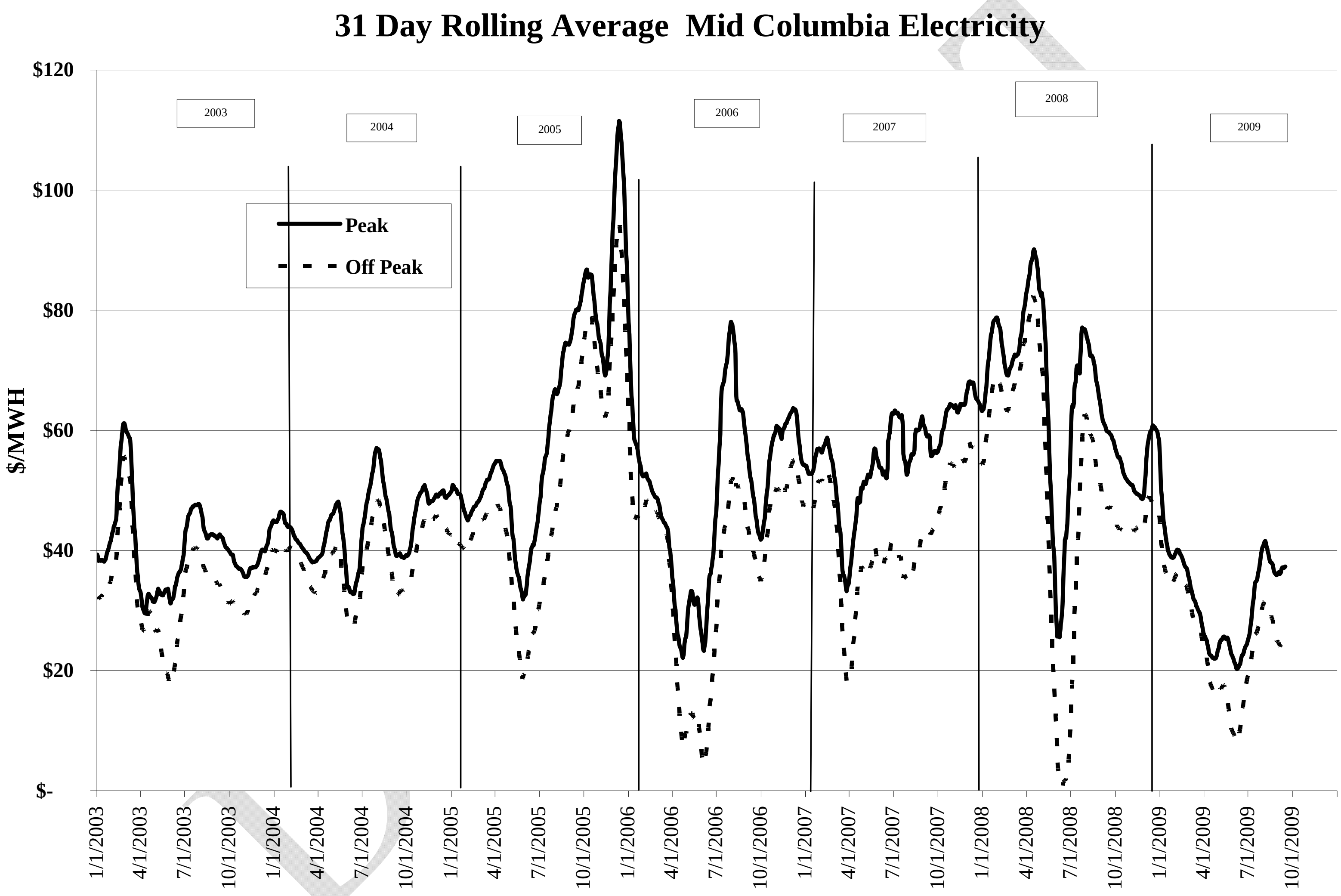
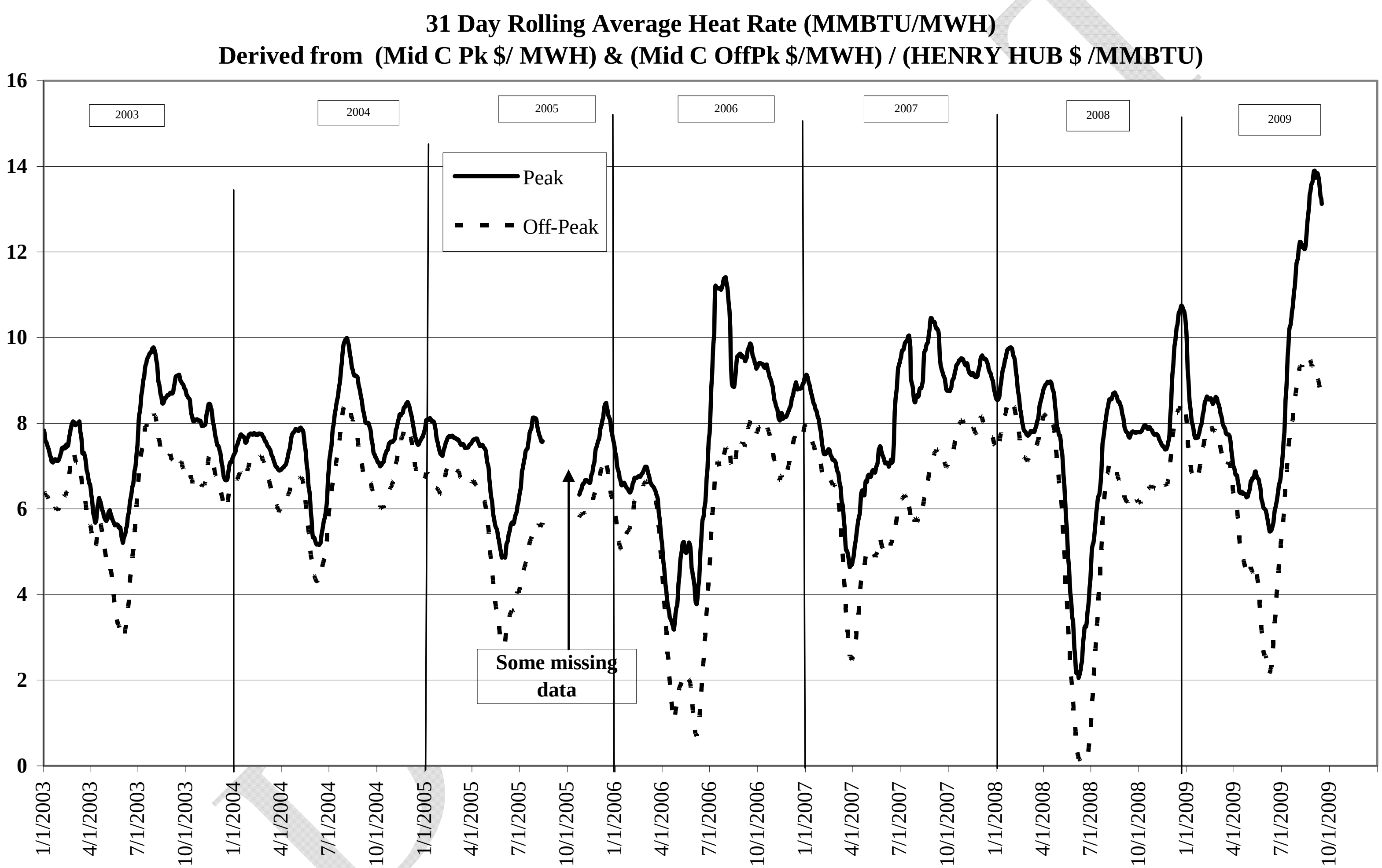


Figure 2.7
Market Heat Rate



Data about the intrinsic variability in these variables was used in the extensive modeling process described. Figures 2.8 through 2.10 present results of that modeling and illustrate potential outputs for the year 2010 for natural gas prices, market heat rates and, then, wholesale electricity

Figure 2.8
Potential Natural Gas Prices, $/MMBTU, for 2010

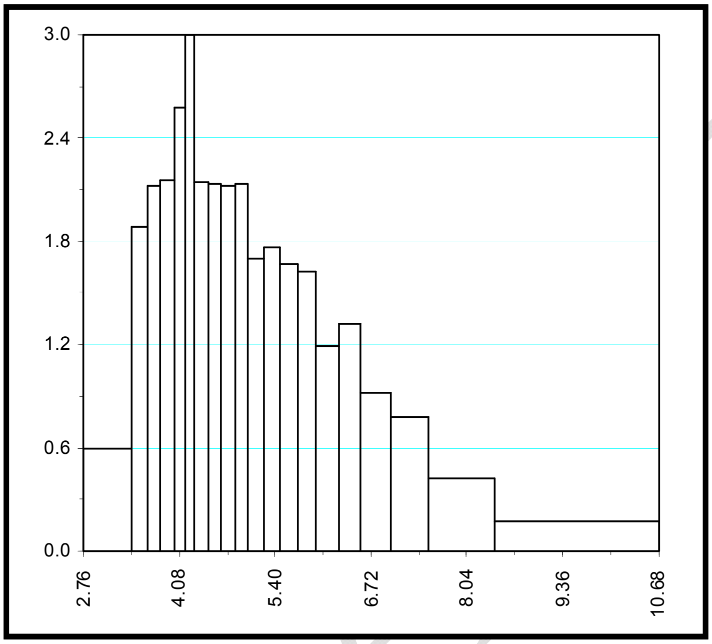


Figure 2.9
Potential Market Heat Rate (MMBTU / MWh) for 2010

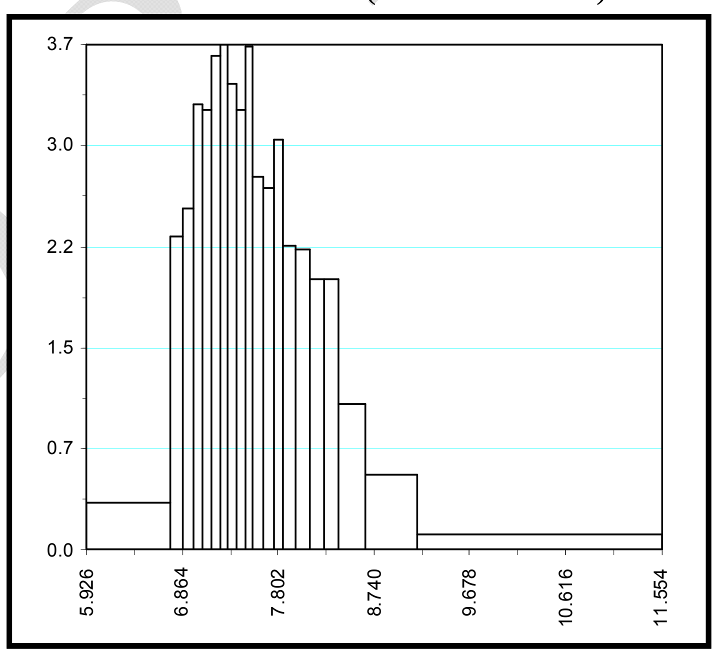
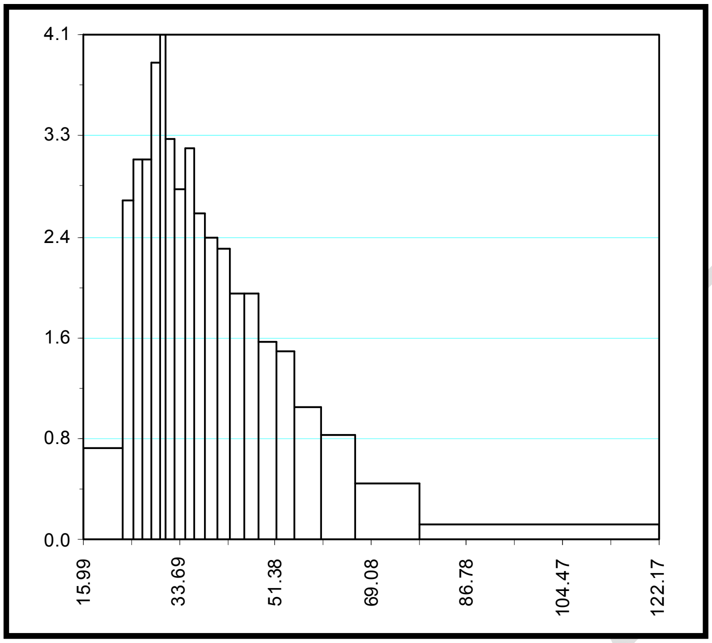


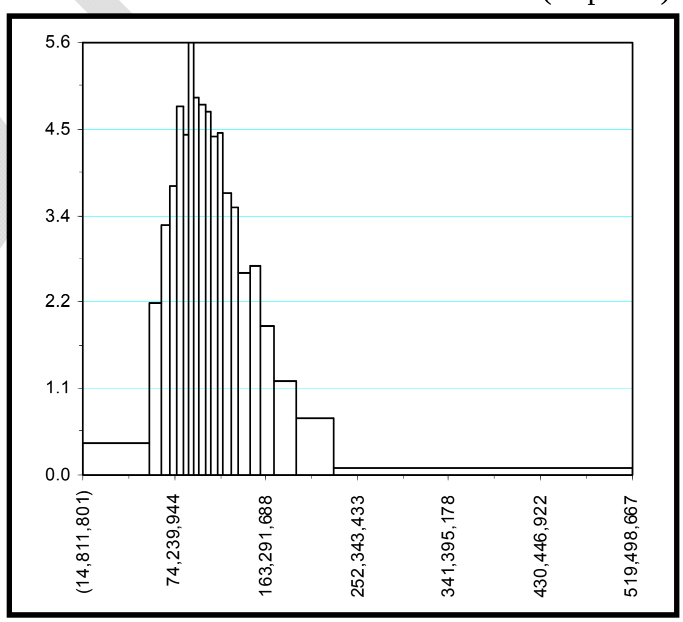
Figure 2.10
Potential Wholesale Electric Energy Market Prices, $/MWh, for 2010



prices. As for the earlier figures of this type, the bottom axis represents the variable and the vertical axis represents the probability density expressed in percent. And, as before, the data have been normalized in the manner described.

Wholesale prices interact with energy available to be sold to produce net wholesale revenue. Figure 2.11 illustrates the potential range of net wholesale revenue for the year 2010. The data

Figure 2.11
Potential Net Wholesale Power Market Revenue (Expense) for 2010



in this figure are the computational results of the interactions of the probability distributions of the previous figures. This figure dramatizes the uncertainty associated with net wholesale revenue, which is the major revenue source that can reduce revenue required from retail customers.

Changing focus slightly from probabilities of outcomes to the simple average of all 2001 scenarios, there have been significant changes to the loads and resources between the 2007-2008 and 2010 Rate Studies that must be taken into account. Table 2.1 illustrates several pertinent pieces of data derived from the studies just mentioned. The simple averages are easy to understand, but it is important to remember that there are many possible outcomes lower and higher than these averages.[8]

The top of Table 2.1 shows the various uses of energy that City Light controls. The various uses are called 'Loads'. The largest load is the Seattle System Load which, in turn, equals retail sales (by far the largest element) plus energy used in City Light's own facilities plus energy lost in transmission and distribution to its customers. The other loads are explained below.

City Light has a contract with Pend Oreille County, Washington, where City Light's large Boundary hydro generation plant is located, to sell or deliver them some power. City Light also returns additional power to the Pend Oreille Public Utility District (called Encroachment) to compensate them for raising the water level below their Box Canyon dam (which is up-river from the Boundary dam that backs up water before it flows through the Boundary power generators). Raising the water level below the Box Canyon dam diminishes the effectiveness of converting water power to electrical power at that site; therefore, the PUD is compensated for the loss of efficiency because of the existence of the Boundary dam.

City Light has had an exchange with the Northern California Power Authority (NCPA) for many years in which City Light delivers power to NCPA in the spring and summer (which the top portion of this table shows) in exchange for receiving energy from them in the winter (which the NCPA entry in the next section of the table shows). The Lucky Peak Exchange is new since the 2007-2008 Rate Study. The actual output of the Lucky Peak generation facility is provided to another party. The average value is shown in the top part of the table, in exchange for a fixed amount returned to City Light, which is shown in the next section of the table.

The last element under loads is the Power Market. For 2010, the table shows the average amount of energy sold to the wholesale market in the 2001 scenarios. Sales in the wholesale market incur transmission losses and the seller must compensate for those losses. The next to last entry in the top section of Table 2.1 shows the average value of energy that must be provided to others to compensate for energy losses associated with wholesale power sales.

The second section of Table 2.1 presents the sources of the energy for all the uses in the top section of the table. It is physically, and computationally, necessary for total sources of power to equal the total uses of power. This section of the table has three subsections. The top-most presents average output from City Light's own resources. The next subsection presents average

[8] It is important not to confuse the simple average of the 2001 outcomes with the mid-point or 50 percent cumulative probability outcome.

values from resources under long-term contracts to City Light. Considerable detail about these contract resources is presented in Chapter 4. Finally, the last subsection represents spot market purchases from the Power Market. These are necessary to: a) supplement City Light resources in certain months in order to serve the utility's retail customers; and b) provide benefits for other transactions, such as buying at a low price in off-peak hours in order to preserve water in dams with which to produce energy that can be sold at higher prices in peak hours.

Summarizing the top two sections of Table 2.1, the projected system load for 2010 is down slightly (9.9 vs. 10.1 million MWh) because of the current economic downturn, which leaves more energy available for wholesale sales. City Light also expects to buy less power from BPA Block (see discussion in Chapter 4). Boundary output is expected to be down slightly because of an improved methodology for forecasting output from the facility. These declines reduce potential wholesale sales. However, more energy is expected to be generated from some resources, which makes more energy available for wholesale sales. The major increases are associated with the Priest Rapids contract, the IRP Resources and the Lucky Peak Exchange. Chapter 4 explains the reasons behind these projected increases, which range from changes in the contracts to availability of a new resource. Expected purchases of power from the wholesale market declined from 0.93 million MWh to about 0.80 million MWh. The average net amount of MWh to be sold on the wholesale market declined from nearly 3.3 to 3.0 million MWh. See the bottom section of Table 2.1 for the net MWh sales to the Power Market. Again, it must be emphasized that these are average values whereas, in fact, there is a wide dispersion of possible outcomes.

The bottom of Table 2.1 shows the previous and current forecasts for wholesale prices and net wholesale MWh sales. City Light is expecting almost $50 million less in net wholesale revenue for the year 2010 than the average values forecasted for 2007 and 2008 in the 2007-2008 Rate Study (down from $170 million to $120 million). The significant drop in expected gas prices between the two periods is the primary contributor. Part of the decline in gas prices is offset by a projected increase in market heat rates. The explanation for this last point revolves around a technical improvement in the construction and projection of market heat rates. The 2007-2008 Rate Study utilized natural gas price forecasts by an external source that was, after some time, considered to be consistently too high. The current procedure uses forward prices that are considered more consistent with reality and are lower than the previous source, thereby increasing the market heat rate.

Table 2.1
Average Values of Some Major Factors Affecting Cash from Wholesale Power Sales, Net

	2007-2008	2010	Diff	% Diff
Uses of Power				
MWh of Electric Energy to Loads	14,900,654	14,633,139	(267,515)	-1.8%
Seattle System Load	10,139,700	9,919,005	(220,695)	-2.2%
Pend Oreille County	370,530	370,022	(508)	
Encroachment	0	40,166	40,166	
NCPA Exchange	90,576	90,580	4	
Lucky Peak Exchange	0	292,981	292,981	
Power Market for Losses	82,657	76,318	(6,339)	-7.7%
Power Market	4,217,191	3,844,065	(373,125)	-8.8%
Sources of Power				
MWh of Electric Energy from Resources	14,900,654	14,633,139	(267,515)	-1.8%
City Light Owned Resources	6,551,608	6,271,819	(279,789)	-4.3%
Ross	738,315	751,587	13,271	1.8%
Diablo	744,867	736,219	(8,648)	-1.2%
Gorge	896,206	883,690	(12,516)	-1.4%
Boundary	4,022,170	3,759,711	(262,458)	-6.5%
South Fork Tolt	57,350	53,829	(3,521)	-6.1%
Cedar Falls	83,281	77,365	(5,916)	-7.1%
Newhalem	9,419	9,418	(1)	0.0%
Long Term Contracts	7,418,123	7,565,221	147,097	2.0%
BPA Slice	3,789,418	3,557,770	(231,648)	-6.1%
BPA Block	2,277,635	2,081,826	(195,809)	-8.6%
High Ross	310,246	310,246	(0)	0.0%
Lucky Peak	288,913	292,981	4,068	1.4%
GCPHA	240,018	239,763	(255)	-0.1%
Priest Rapids	19,805	228,414	208,609	
Wind Resources	383,378	402,844	19,466	5.1%
SPI	0	26,280	26,280	
SMUD	0	19,368	19,368	
IRP Resources	0	50,633	50,633	
NCPA Exchange	108,711	108,696	(15)	
Lucky Peak Exchange	0	246,400	246,400	
Spot Market Purchases				
Power Market	930,923	796,099	(134,823)	-14.5%
Cash from Wholesale Power Sales, Net	169,698,714	119,973,371	(49,725,343)	-29.3%
MWh of Energy to Wholesales Power Sales, Net	3,286,268	3,047,966	(238,302)	-7.3%
Dollars per MWH of Energy to Power Market	51.47	39.36	(12.11)	-23.5%
Dollars per MMBTU of Natural Gas	7.83	5.34	(2.49)	-31.8%
Ratio of Electric Energy Price to Natural Gas Price	6.57	7.37	0.81	12.3%

Chapter 3 - Cash from All Other Sources

In addition to revenue from retail and wholesale power sales, City Light receives operating cash from other sources such as long-term power contracts, revenue from transmission and power-related services, investment income and other fees and charges. This group of revenues comprises the category called Cash from All Other Sources and as displayed in Table 3.1 is projected to total $70.2 million in 2010. This is an increase of $13.6 million over the amount that was forecasted in the 2007-2008 Rate Study.

Table 3.1
Cash from All Other Sources

	2007-2008 Rate Study	Forecast 2010	Change in Cash Flow
Cash Flow (in $)			
Cash from All Other Sources	**56,624,152**	**70,224,911**	**13,600,760**
Cash from Power Contracts	15,593,274	22,344,800	6,751,526
Cash from Power Marketing, Net	12,434,432	14,460,718	2,026,287
Cash from Other Sources	28,596,446	33,419,393	4,822,947
Cash from Power Contracts	**15,593,274**	**22,344,800**	**6,751,526**
Cash from BPA Residential Exchange Credit	0	5,982,756	5,982,756
Cash from Article 49 Sales to Pend Oreille County	1,589,150	1,763,888	174,738
Cash from Seattle Share of Priest Rapids Revenue	8,765,424	8,590,472	(174,952)
Cash from BPA Credit for South Fork Tolt	3,023,700	3,521,368	497,668
Cash from BPA Credit for Conservation	2,215,000	2,486,316	271,316
Cash from Power Marketing, Net	**12,434,432**	**14,460,718**	**2,026,287**
Cash from Transmission Services	4,280,911	4,579,411	298,500
Cash from Basis Sales, Net	519,926	1,500,000	980,075
Cash from Other Services, Net	7,633,595	8,381,307	747,712
Cash from Other Sources	**28,596,446**	**33,419,393**	**4,822,947**
Cash from Other Revenue	14,644,015	23,559,782	8,915,767
Cash from Investments	5,721,892	4,208,965	(1,512,927)
Cash from Sale of Property	5,289,851	1,024,397	(4,265,454)
Cash from Suburban Undergrounding	0	621,676	621,676
Cash from Operating Fees and Grants	300,000	710,000	410,000
Cash from Distribution Capacity Charge	0	199,702	199,702
Cash from Green Power Programs	750,000	1,082,095	332,095
Cash from Power Factor Charges	2,459,981	2,612,936	152,955
Cash to Credits for Transformation	317,787	333,658	15,872
Cash to Emergency Low-income Assistance Program	251,507	266,502	14,996

As displayed in Table 3.1, Cash from All Other Sources can be divided into three sub-categories: Cash from Power Contracts, Cash from Power Marketing, Net and Cash from Other Sources. This section provides a description of each sub-category and their projected changes in 2010 as compared to the 2007-2008 Rate Study.

3.1 Cash from Power Contracts

Cash from Power Contracts is projected to be $22.3 million in 2010, which is $6.8 million higher than the amount projected in the 2007-2008 Rate Study. Most of this increase is due to the addition of the BPA Residential Exchange Credit, which is projected to be about $6 million in 2010.

3.1.1 BPA Residential Exchange Credit

BPA reimburses City Light and other public utilities for overpayment in prior years of charges related to BPA's Residential Exchange program with investor-owned utilities. City Light began receiving these credits in 2008 and expects to continue receiving them through September 2015. This is a new source of cash which was not available in 2007-2008.

3.1.2 Article 49 Sales to Pend Oreille County

Part of Boundary Dam output is sold to the county in which it is located, Pend Oreille County. According to Article 49 of the original license issued by the Federal Energy Regulatory Commission (FERC) for the Boundary Project, part of the generation at this site must be made available to Pend Oreille County Public Utility District (PUD) No. 1 to meet its load growth. Pend Oreille County PUD has been withdrawing the maximum amount of about 42.2 average MW per year since 2006 from Boundary. This withdrawal is expected to continue in 2010. The sales revenue is projected to increase to $1.8 million in 2010, which is about $0.2 million higher than the amount forecasted in 2007-2008. This difference is explained by the increase in prices that City Light charges the PUD because of increased operating costs at Boundary.

3.1.3 Seattle Share of Priest Rapids Revenue

On November 1, 2005, in compliance with a 1998 FERC ruling, 30 percent of the output of the Priest Rapids Project was offered for sale pursuant to market-based principles to entities in the seven-state northwest region. Under the terms of contracts entered into with Grant County PUD in 2002, the Department has contracted to receive a share of the profits derived from the sale of the 30 percent share of Priest Rapids' output, which will include outputs from both Priest Rapids and Wanapum Dams starting in November 2009. City Light projects that it will receive $8.6 million in revenues from the Priest Rapids project in 2010. This is a decrease of almost $0.2 million from the 2007-2008 Rate Study and is due to lower forward market prices in 2010.

3.1.4 BPA Credit for South Fork Tolt

BPA reimburses Seattle City Light for developing a new power generation facility on the South Fork of the Tolt River. The South Fork of the Tolt Project came on line in November 1995. This project uses the hydroelectric potential of the Seattle Water Department municipal water supply dam, located northeast of Carnation. Under expected water conditions it provides 6.5 average MW. This credit is projected to total $3.5 million in 2010 or $0.5 million higher than the forecasted amount in the 2007-2008 Rate Study. The increase in the annual billing credits is due to changes in BPA rates.

3.1.5 BPA Credit for Conservation

BPA currently provides a Conservation Rate Credit for City Light. The Utility claims this credit by reporting qualifying activities to BPA. These activities can be investments in conservation, donations to certain organizations or purchases of renewable resources. The Conservation Rate Credit is about $2.5 million in 2010. It is an increase of almost $0.3 million from the 2007-2008 Rate Study. BPA calculates the credit amount based on City Light's BPA Slice and Block purchases. City Light's monthly credit was calculated by dividing Seattle's Fiscal Year 2010-2011 total qualifying purchases (kWh) by 24 and multiplying the result by 0.50 mills/kWh. The annual amount was determined by multiplying the rounded monthly credit by 12.

3.2 Cash from Power Marketing, Net

City Light generates revenue from basis sales, capacity sales, and other power related services. Cash from power marketing activities projected in 2010 is around $14.5 million and is $2.0 million higher than the amount assumed in the 2007-2008 Rate Study. Reasons for the increase include revenue from basis trades, capacity sales and green tags.

3.2.1 Transmission Services

Under its Point-to-Point transmission service agreement with BPA and others, City Light is permitted to market its unused transmission capacity. Resale price cannot exceed the cost of transmission but can be discounted at the discretion of the reseller. The revenue from this source has been quite variable over the years because it depends on both City Light's transmission surplus and its marketing effort. Since 2005, City Light senior management has emphasized the importance of this resource and encouraged more active marketing. In addition, City Light has three contracts with Snohomish County PUD (SNOPUD) for North Mountain Substation: an Operations and Maintenance Agreement, a Power Transfer Agreement, and a Telecommunications Agreement. These contracts reimburse City Light for expenditures made to operate and maintain the substation and pay for transmission of power to SNOPUD over City Light's Skagit Transmission Lines. Cash from Transmission Services, which include wheeling to North Mountain Substation and other wheeling sales, is forecasted to be $4.6 million in 2010. This is an increase of $0.3 million over the 2007-2008 Rate Study. Cash from Transmission Services is assumed to increase by the rate of inflation.

3.2.2 Basis Sales

Basis trades are paired, simultaneous power purchase and sale transactions at different locations that take advantage of the difference in market value of energy at two locations (e.g., Mid-Columbia and California/Oregon border [or COB]). These types of trades may occur at any location where City Light has access to transmission services. Basis sales, net of purchases, are projected to be $1.5 million in 2010. This is an increase of $1 million over the 2007-2008 forecast. City Light projects a higher volume of basis sales in 2010 than it had forecasted in the 2007-2008 Rate Study.

3.2.3 Other Services

Cash from other services is projected to be $8.4 million or $.7 million higher than the amount forecasted in the 2007-2008 Rate Study. The increase is due to the growth in capacity and green tag sales. Capacity sales include reserve capacity sales and general capacity sales. City Light sells the right to purchase reserve capacity to utilities, power marketers and other entities that purchase power from BPA, enabling them to meet their required reserves (i.e., the requirement that a utility have capacity at its disposal that exceeds its expected peak demand by a certain percentage). City Light also sells the right to delivery of energy to counterparties who have the choice of determining the amount and timing of that delivery; these are called “capacity sales.” Green tag sales (i.e., renewable energy credits) are projected to increase as the Department continues to acquire new resources with green attributes that can be sold to other wholesale power providers.

3.3 Cash from Other Sources

Cash from other sources is projected to total $33.4 million in 2010, which is $4.8 million higher than the amount in the 2007-2008 Rate Study. This sub-category includes cash from a variety of sources such as sales of property, investment income, operating fees, and grants.

3.3.1 Other Revenue

Other revenue comprises income the Department earns from fees and charges for a variety of services. These sources of income offset revenue requirements and reduce the amount of revenue collected from rates. As displayed in Table 3.2 (next page) this other revenue is projected to be $23.6 million. It is an increase of $8.9 million over the 2007-2008 Rate Study, which is largely due to the Department’s aggressive pursuit of additional revenue for 2010. Descriptions of each of the items that comprise the other revenue category and their forecasted changes are provided below.

- ***Late Payment Fees***

Delinquent customer balances of $75 or more are assessed the greater of $10 or 1% per month. Revenue from these fees varies with rates and economic conditions over time. In addition, City Light had problems with its billing system in the early 2000s but has resolved them since then.

Late payment fees are expected to increase from about $3.2 million in the 2007-2008 Rate Study to $3.6 million in 2010.

Table 3.2
Cash from Other Revenue

	2007-2008 Rate Study	Forecast 2010	Change in Cash Flow
Cash Flow (in $)			
Cash from Other Revenue	**14,644,015**	**23,559,781**	**8,915,766**
Late Payment Fees	3,188,438	3,622,266	433,828
Revenue From Damage	1,455,792	1,333,540	(122,252)
Other O&M Revenue	3,576,434	6,619,630	3,043,196
Rental Income	1,767,747	1,260,631	(507,116)
Construction Charges	415,941	10,505	(405,436)
Transmission Attachments & Cell Sites	636,982	1,394,831	757,850
Pole Attachments	1,000,000	1,366,381	366,381
Account Change Fee	1,407,454	1,448,010	40,556
Miscellaneous Rentals	172,234	183,412	11,179
Reconnect Charges	227,952	242,747	14,796
Miscellaneous Income	795,044	(949,474)	(1,744,518)
Cash from Executive Decisions	0	7,027,302	7,027,302

- ***Revenue from Damage***

The Department bills those responsible for damage to its property and equipment, such as damage to streetlight poles, vaults, ducts, etc., for any repairs required to restore the functionality of the property or equipment. Prior to 2000, these billings were recorded as offsets to expense for property and equipment maintenance. Since that time, they have been recorded as a source of operating revenue. In the 2007-2008 Rate Study revenue from damage to property and equipment was forecasted to be about $1.4 million. Based on actual 2009 experience, these revenues are forecasted to be $1.3 million in 2010.

- ***Other O&M Revenue***

These revenues encompass income earned from a very broad range of billable O&M charges, including charges for inspections of meters and other technical equipment, building maintenance charges and recreational charges such as those for Skagit tours. Based on actual amounts in recent years, these revenues are projected to increase by $3.0 million in 2010 over the amount forecasted in the 2007-2008 Rate Study.

- ***Rental Income***

Rental income is derived from rental of City Light property including underground ducts and vaults, housing units at the Skagit project, and transmission and distribution rights-of-way. Based on the average level in the past several years, property rental income is expected to decrease by $0.5 million in 2010 compared to the amount in the 2007-2008 Rate Study.

- ***Construction Charges***

Construction charges are paid by customers for City Light services during phases of construction activity on the customer premises related to the delivery of electricity. The Department bills customers for accounting, engineering work, and administrative overhead. Based on recent history, construction charges are expected to be only a little bit over $10,000 in 2010.

- ***Transmission Attachments and Cell Sites***

Revenues from rentals for transmission attachments and cellular sites are forecasted to be $1.4 million in 2010, an increase of $0.8 million over the amount in the 2007-2008 Rate Study. This large difference can be explained by the growth in volume and the fact that the value of the contracts has been increasing at about 4% annually.

- ***Pole Attachments***

Ordinance 119395, passed in March 1999, allows City Light to charge two different rates for pole attachments. Attachments billed at the traditional cost-based rates are called Class 1 attachments and a new type of attachment, billed at a market-based rate, is called a Class 2 attachment. Class 1 attachments typically consist of television or computer cable strung pole-to-pole. Class 2 attachments are defined as “non-linear, nonwire line devices, related to advanced and competitive communication technologies, such as wireless communication antennas and remote-site cameras.” Ordinance 119395 allows City Light to negotiate market-based rates for these types of attachments. Table 3.2 shows revenue collected from both types of attachments, which is forecasted to increase by $0.4 million in 2010 over the 2007-2008 Rate Study amount due to the growth in the number of attachments.

- ***Account Change Fee***

City Light charges a fee when customers open an account. Account service revenues are estimated using a forecast of the number of account changes and the projected fees charged for changing an account. A fee increase was implemented in late 2006. These revenues are projected to increase by a little over $40,000 in 2010 over the amount in the 2007-2008 Rate Study, which is explained by the growth in the number of accounts.

- ***Miscellaneous Rentals***

These revenues are collected from commercial customers for rental of equipment such as transformers. Miscellaneous rental income is forecasted to be around $0.2 million in 2010, which is about the same level as it was in the 2007-2008 Rate Study.

- ***Reconnect Charges***

City Light charges customers for the cost of processing returned checks, making field visits to collect on delinquent bills, and reconnecting electric service. Revenues from these sources in 2010 are forecasted to remain near the 2007-2008 Rate Study level of $0.2 million.

- ***Miscellaneous Income***

Miscellaneous income includes income, net of expenses, for non-operating property. This includes billable work performed on plant that is considered surplus property because it is no longer used to generate electricity. Miscellaneous income often includes one-time receipts such as refunds or reimbursements that can vary greatly in amount, making this a difficult revenue category to forecast with any precision. In 2009, the Department of Finance lent City Light $2.1 million for maintenance of streetlights owned by the City by prepaying some expected streetlight rate billings for 2010. The Department will reimburse this amount in 2010, causing projected net miscellaneous income to be negative $1 million.

- ***Cash from Executive Decisions***

The Department has been aggressively pursuing additional revenue for 2010 to improve financial stability. City Light added $7 million of revenue from these decisions, the breakdown of which is shown in Table 3.3. The main sources of the revenue are the additional renewable energy credits, revenue from curbing energy losses caused by electric current diversion, sale of excess transmission capacity, and reimbursement for work on cell sites.

Table 3.3
Cash from Executive Decisions

	2010
Cash Flow (in $)	
Cash from Executive Decisions	**7,027,302**
Additional Revenue from Renewable Energy Credits	500,000
Electrical Current Diversion	2,000,000
Pole and Streetlight Damage Claims	200,000
Un-Permitted House Re-wires	56,000
No Longer Allow Flat Rate Billings	50,000
Estimated Bill Charge	50,000
Sale of Surplus Properties	700,700
Monetize Excess Transmission Capacity	2,000,000
Revenue Offset - Reimbursable Cell Site Work	1,470,602

3.3.2 Investments

City Light's investment income is projected to decline by $1.5 million to $4.2 million in 2010 as compared to the 2007-2008 Rate Study. Investment income varies with the level of funds in cash balances. These levels vary with actual retail and wholesale sales revenues, operating expenses, capital expenditures, contributions and grants, proceeds from the sale of bonds, and cash reserves and minimum balances required to meet financial policies set by the City Council. The projected decrease in the investment income is due to lower cash balances as well as lower interest rates.

3.3.3 Sale of Property

The Department sells or otherwise disposes of surplus real property. Sales of surplus property are $4.3 million lower in the current 2010 forecast than those projected in the forecast used to set rates in 2007-2008 because the sale of an $8.5 million property in South Lake Union has been delayed for several years and removed from the forecast until it becomes more certain.

3.3.4 Suburban Undergrounding

Customers in suburban franchise cities must reimburse City Light over time for undergrounding projects carried out by City Light at the request of their suburban city governments. Cash from Suburban Cities undergrounding was included in Cash from Contributions in the 2007-2008 Rate Study. In the current forecast for 2010, City Light has decided to include it in operating cash from other sources because it can be used as cash available for debt service to offset revenue requirements and reduce the percentage of the rate increase. The projected amount for 2010 is about $0.6 million.

3.3.5 Operating Fees and Grants

Operating grants are any grant funds received from Federal, State or local agencies in support of City Light's operating expenses. The amount of grants received and the purposes for which grant funding is provided can vary significantly from year to year. In the 2007-2008 Rate Study, City Light forecasted it would receive $0.3 million for the Lighting Design Lab from the Northwest Energy Efficiency Alliance. In 2010, the Department projects that it will receive $0.7 million in grants, the majority of which is a grant for toxic cleanup.

3.3.6 Distribution Capacity Charge

Distribution capacity charges went into effect on January 1, 2007. City Light charges Medium, Large and High Demand customers for reserve distribution capacity on a circuit which is different from their normal service circuit. These charges are projected to be about $0.2 million in 2010, which is approximately what City Light has been collecting in previous years.

3.3.7 Green Power Programs

City Light receives revenues from two voluntary green power programs for residential and business customers. The first program is called "Green Power." Customers who pay into the Green Power program support solar projects in Seattle. This program funds local renewable energy demonstration projects that create awareness of renewable energy within our community, and help grow the local market for solar and other green technologies. The second program is called "Green Up." By enrolling in Green Up, customers purchase green power for a portion of their electricity use and demonstrate their support for wind power and other new renewable energy projects in the Northwest. Green Up customers make voluntary payments on their electricity bill to cover the slightly higher cost of producing and integrating renewable energy into the Northwest grid. These funds are used to acquire Renewable Energy Credits equal to the amount of customer demand. The projected revenue from voluntary green power programs for 2010 is $1.1 million, a $0.3 million increase over the 2007-2008 forecast. This increase is due to several factors such as people becoming more aware of the Green Power and Green Up Programs through Seattle City Light marketing efforts, general public concern about climate change, and desire to mitigate global warming by substituting renewable energy sources for non-renewable resources.

3.3.8 Power Factor Charges

Seattle City Light adds power factor charges to the bills of some commercial and industrial customers that have a power factor that is lower than the utility standard of 0.97. These charges are projected to increase by about $0.2 million in 2010 as compared to the 2007-2008 Rate Study. This difference is due to fluctuations in customer consumption patterns over the year and the increasing number of power factor meters installed at customer locations.

3.3.9 Credits for Transformation

Our base rates include a charge for the cost of transformers to City Light. Therefore, City Light reimburses customers who provide their own transformers based on kW of demand. The forecasted expense for 2010 is $0.3 million, which is about the same level as it was in the 2007-2008 Rate Study.

3.3.10 Emergency Low-income Assistance Program (ELIA)

City Light's Emergency Low-income Assistance Program (ELIA) provides assistance to pay up to 50 percent of a customer's delinquent bill, with a maximum of $200, for customers in crisis situations who have received a 24-hour shut-off notice. For more detailed information about ELIA see Chapter 6. As in the 2007-2008 Rate Study, the expenses are projected to be around $0.3 million.

Chapter 4 - Cash to Power Contracts

4.1 Overview

Table 4.1 presents an overview of costs for purchased power in the 2007-2008 Rate Study and the 2010 Forecast.

Table 4.1
Purchased Power Contracts

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Purchased Power	275,978,084	293,394,002	17,415,918
Bonneville Power Administration	178,927,525	172,418,816	-6,508,709
Wind Resources	20,227,300	21,163,611	936,311
High Ross	13,047,867	13,075,067	27,200
Lucky Peak	13,988,650	6,065,000	-7,923,650
Grand Coulee	4,069,400	5,014,000	944,600
Priest Rapids	1,628,700	12,441,250	10,812,550
SPI Purchase	0	1,716,407	1,716,407
IRP Resources	0	2,870,691	2,870,691
Water for Power	4,363,317	10,469,557	6,106,241
Wheeling	39,725,326	48,159,603	8,434,277

Total costs rose by $17.4 million between what was projected as the average cost for 2007 and 2008 in the 2007-2008 Rate Study and what is now projected for 2010. Not all individual costs rose. In fact, the single largest contract, with the Bonneville Power Administration, saw its annual cost drop $6.5 million and the purchase cost of Lucky Peak declined by $7.9 million. These significant reductions were offset by increases in costs for other resources, the largest of which was Priest Rapids, $10.8 million. Additionally, fees that must be paid for land and water rights used in production – called Water for Power – increased by $6.1 million. Further, Wheeling costs associated with long distance transmission over lines owned by others increased by $8.4 million. Details follow.

4.2 Bonneville Power Administration

The Bonneville Power Administration (BPA) 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. These resources, called the Federal System, have a peak generating capacity of 24,080 MW and a firm energy capability of approximately 8,500 average MW. These projects are built and operated by the United States Bureau of Reclamation and the United States Army Corps of Engineers 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 about 130 utility and governmental customers in the Pacific Northwest. Bonneville also sells power directly to three industrial customers in the region. Bonneville is required by law to give preference to government-owned utilities and to residential 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 City Light over the ten-year period beginning October 1, 2001. Under the contract, power is delivered in two forms: a shaped "Block" and a "Slice". Through the Block product, power is delivered to the Department in stipulated monthly amounts. 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 several times 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 annual entitlement to Block power between September 29, 2009, till the end of this contract on September 30, 2011, is 237.65 average MW.

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 406 MW over all water conditions.

Table 4.2 presents a comparison of the major factors affecting BPA costs as they were projected in the 2007-2008 Rate Study and as they are now estimated or projected for 2010. As noted in that table, total costs declined $6.5 million. This reduction was supported by cost declines for both the Slice (-$4.06 million) and the Block (-$2.45 million) product between what was projected on average for 2007 and 2008 in the 2007-2008 Rate Study and what is now projected.

A methodology useful for analyzing changes in cost for the Block product, and changes in cost for other power purchases discussed in subsequent sections, looks at initial and new rates charged and energy purchased. If we think of the new annual average rate and new amount of power to equal the initial rate ($\underline{\text{rate}}$) and initial amount of power ($\underline{\text{MWh}}$) plus some increment (Δ) to rate and power, then we can see that the change in costs works out like this, where $\underline{\text{rate}}$ and $\underline{\text{MWh}}$ refer to initial values, i.e., values expected for 2007-2008 as of the 2007-2008 Rate Study:

$$
\begin{aligned}
\text{Change in total cost} &= \underline{\text{new rate}} * \underline{\text{new MWh}} - \underline{(\text{rate} * \text{MWh})} \\
&= (\underline{\text{rate} + \Delta\ \text{rate}})*(\underline{\text{MWh} + \Delta\ \text{MWh}}) - (\underline{\text{rate} * \text{MWh}}) \\
&= (\underline{\text{rate*MWh}}) + (\underline{\text{MWh*}\Delta\text{rate}}) + (\underline{\text{rate*}\Delta\text{MWh}}) + (\underline{\Delta\text{rate*}\Delta\text{MWh}}) - (\underline{\text{rate*MWh}}) \\
&= (\underline{\text{MWh*}\Delta\ \text{rate}}) + (\underline{\text{rate*}\Delta\ \text{MWh}}) + (\underline{\Delta\ \text{rate*}\Delta\ \text{MWh}})
\end{aligned}
$$

This decomposition of change in cost is used to analyze change in Block costs as well as changes in cost for several other resources described below.

Table 4.2
Bonneville Power Administration

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Total BPA	178,927,525	172,418,816	(6,508,708)
Slice	114,980,605	110,923,380	(4,057,225)
Block	63,946,919	61,495,436	(2,451,483)
		Slice	
$/% ownership/mth	1,877,054	1,962,525	85,471
% Ownership	4.6676	4.6676	-
IOU Res Exch $/mth/%	65,043	-	(65,043)
Ann. Base Cost	105,136,047	109,923,380	4,787,333
Ann. IOU Res Exch Cost	3,643,136	-	(3,643,136)
Ann.True-Up Adjustments	6,201,422	1,000,000	(5,201,422)
Sum	114,980,605	110,923,380	(4,057,225)
		Block	
MWh	2,277,635	2,081,826	(195,809)
Avg. Rate	28.08	29.54	1.46
'07-'08 MWh * Δ Avg Rt			3,332,554
'07-'08 Avg Rt * Δ MWh			(5,497,537)
Δ Avg Rt * Δ MWh			(286,501)
Product or Sum	63,946,919	61,495,436	(2,451,483)

The decline in Slice costs is associated with reductions in what could be called 'extra' costs. These reductions in 'extra' costs offset an increase in base Slice costs. In the 2007-2008 Rate Study, there was an expectation that the monthly cost per percentage ownership would remain fixed for the last five years of the current contract (extending from October 2006 through September 2011). In fact, there was one small decrease in this ownership cost starting in October 2008 but a 4.4 percent increase (over the lower rate the preceding year) applies from October 1, 2009 through September 2011. Thus, on this account, base Slice costs increase (nearly $4.8 million) in 2010 compared to the average of projected costs for 2007-2008.

As of the 2007-2008 Rate Study, BPA made payments to Investor Owned Utilities (IOUs) in lieu of selling them low cost power for their residential and small general service customers. That cost to BPA was passed on to BPA's other customers in the form of an extra charge per month per percentage ownership of the Slice product. Subsequently, this charge was determined to be illegal by the Ninth Circuit Court of Appeals so that charge is no longer levied. Removal of that IOU charge reduced the annual cost of the Slice product by $3.6 million. This reduction is in effect till the end of the current contract (end of September, 2011).

An even larger, though one-time, reduction in Slice cost is associated with the annual true up costs mentioned above. There was an expectation at the time of the 2007-2008 Rate Study that there would be sizable (larger than 'normal') true up charges in the then near-term levied on the Slice product, especially in 2007. (Those expectations were borne out in fact.) Expectations at this time of the true up costs to be paid in 2010 are down to their 'normal' level of $1 million. Thus, even though this is a one-time benefit, this difference in true-up costs reduces the expected Slice bill by $5.2 million in 2010 compared to the average for 2007-2008 expected in the 2007-2008 Rate Study.

Costs for power from the Block product in 2010 are expected to be lower than the average expected for 2007-2008 in the 2007-2008 Rate Study. Several factors play a role in the reduction in expected Block costs. The methodology mentioned above is useful in decomposing the factors affecting the change in Block costs.

The 2007-2008 Rate Study expected base prices for Block power (demand charges, peak period and off-peak period energy charges; all of which vary by month) to remain unchanged till the end of the current contract. Similar to Slice, there was, in fact, a small decrease in these prices effective in October 2008. But the Department has a new signed amendment to the power sales agreement that increases all Block charges in October 2009, and, again, in October 2010. The final rates for calendar year 2010 are uniformly higher than the base rates in the 2007-2008 Rate Study. This change in Block rates tends to increase Block costs.

But there are offsetting forces. Since the 2007-2008 Rate Study, the Department has produced more conservation savings that qualify for payments from BPA than were expected in the last rate case. But with payments from BPA for realized conservation savings comes a reduction in the amount of Block power that the Department is permitted to buy. The Department's entitlement to Block power has decreased about 22.35 annual average MW since the 2007-2008 Rate Study. This reduction in Block power tends to reduce Block costs.

As can be seen in Table 4.2, the impact of changes on both rates and power on total Block cost can be decomposed into these last three terms. Since the change in rate is positive, the first term (<u>MWh*Δ rate</u>) is positive but since the change in MWh is negative, the next two terms are negative, and for the given facts, they swamp the effect of the first term. Hence, the reduction in Block power is a larger (negative) effect on Block power costs than the increase in average rates, in this case.

4.3 Wind Resources

An October 2001 agreement provides for City Light's purchase of wind-generated energy and associated environmental attributes (such as offsets or emission reduction credits) from PacifiCorp Power Marketing (PPM). City Light purchases a percentage of the output from the

State Line Wind Project near the Columbia River in eastern Washington and Oregon. City Light's share has a maximum output of 175 MW, and averages about 52 MW, or 30% of the total capacity. The contract terms are from July 1, 2004, through December 31, 2021.

In 2001, City Light 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. City Light has not sold these services to PPM since the beginning of 2004, however, because all of the State Line Wind Project's energy is now fully subscribed to purchasers under long-term contracts, including Seattle, so there is no longer any surplus available for PPM. City Light received 432,058 MWh of wind energy under the PPM contract in 2008.

Table 4.3 indicates there has been no material change in the average price of wind power since the 2007-2008 Rate Study and the expectation of an increase in costs of $0.9 million is associated with the increase in projected power expected to be received from this project.

Table 4.3
Wind Power Costs

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Wind Resources	20,227,300	21,163,611	936,311
MWh	383,378	402,844	19,466
Power Cost	15,231,200		
Integration & Exch cost	4,996,100		
$/MWh, Power	39.73		
$/MWh, Int & Exch	13.03		
$/MWh, Total	52.76	52.54	(0.23)
'07-'08 MWh * Δ Avg Rt			(86,345)
'07-'08 Avg Rt * Δ MWh			1,027,040
Δ Avg Rt * Δ MWh			(4,384)
Product or Sum	20,227,300	21,163,611	936,311

4.4 High Ross

In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia provides City Light with power equivalent to that which would have resulted from an addition to the height of Ross Dam. The agreement was ratified through a treaty between Canada and the United States the same year. The power is to be received for 80 years, and delivery of power began in 1986. City Light will make annual payments to British Columbia of $21.8 million through 2020, which represents the estimated debt service costs City Light would have incurred had the addition been constructed. City Light also pays British Columbia the equivalent of the Operation and Maintenance cost which would have been incurred if the High Ross project had been built. The payments are charged to expense over a period of 50 years through 2035. Expected expenses for this project are stable. City Light received 310,257 MWh of energy from this resource in 2008. Table 4.4 presents data from the 2007-2008 Rate Study and the 2010 forecast.

Table 4.4
High Ross

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
High Ross	13,047,867	13,075,067	27,200
MWh	310,246	310,246	0
$/MWh, Total	42.06	42.14	0.09
'07-'08 MWh * Δ Avg Rt			27,200
'07-'08 Avg Rt * Δ MWh			-
Δ Avg Rt * Δ MWh			-
Product or Sum	13,047,867	13,075,067	27,200

4.5 Lucky Peak

The Lucky Peak Hydroelectric Power Plant (Lucky Peak) was developed by three Idaho irrigation districts and one Oregon irrigation district (The "Districts"). It began operation in 1988, and 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 2008 was 310,775 MWh. Since generation is concentrated in the summer months, the plant has no peak capability during City Light's winter peak period.

City Light entered into a 50-year power purchase and sales contract in 1984 with the Districts under which City Light will purchase all energy generated by Lucky Peak, in exchange for payment of costs associated with the plant and royalty payments to the Districts. City Light 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.

City Light has sold the actual net output of the Lucky Peak plant for the last several years. The output has been sold, again, for calendar year 2010. The purchaser, in exchange for the actual output, will deliver to City Light at the Mid Columbia trading hub 100 MW flat in the heavy load hours for each of the months in the first quarter and 50 MW flat in the heavy load hours for the fourth quarter of the year. Additionally, the purchaser will deliver 100 MW flat in the light load hours in the months of January and February.

City Light's contract with the Districts calls for City Light to make annual payments for ownership and maintenance costs, royalty payments to the Districts and debt service payments. Debt service costs, though, came to a conclusion in June 2008. Table 4.5 presents the costs for the combination of these three elements for the 2007-2008 Rate Study and the 2010 forecast.

Table 4.5
Lucky Peak

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Lucky Peak	13,988,650	6,065,000	-7,923,650
MWh	288,914	292,981	4,068
$/MWh, Total	48.42	20.70	(27.72)
'07-'08 MWh * Δ Avg Rt			(8,007,851)
'07-'08 Avg Rt * Δ MWh			196,941
Δ Avg Rt * Δ MWh			(112,739)
Product or Sum	13,988,650	6,065,000	(7,923,650)

4.6 Grand Coulee

City Light, 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 2008 the Department received 259,794 MWh from the project. Total City Light costs are expected to increase just over $0.9 million in 2010 compared to cost projections in the 2007-2008 Rate Study because of expected increases in operating costs.

Table 4.6
Grand Coulee

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Grand Coulee	4,069,400	5,014,000	944,600
MWh	240,018	239,763	-255
$/MWh, Total	16.95	20.91	3.96
'07-'08 MWh * Δ Avg Rt			949,933
'07-'08 Avg Rt * Δ MWh			(4,323)
Δ Avg Rt * Δ MWh			(1,009)
Product or Sum	4,069,400	5,014,000	944,600

4.7 Priest Rapids

Grant County (WA) Public Utility District No. 2 (Grant PUD) has two dams on the Columbia river: Priest Rapids and Wanapum. Jointly, the two dams are referred to as “WAPR.” Grant

PUD sold shares of some of the output of those dams to other utilities. Priest Rapids was developed first and City Light had a contract from its initial on-line date to purchase eight percent of the output of that facility. City Light did not enter into a contract to take power, initially, from the Wanapum dam when it came on-line. Both dams have had to go through a re-licensing process in recent years with FERC. The original collection of other utilities that had purchased output from these two dams were given an opportunity to purchase output, again, but in addition, a number of other utilities filed petitions in the relicensing process that they, too, wanted to participate in the output of these dams.

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. The remaining 30 percent would be 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.

The legal recognition of the rights of all parties has resulted in an extremely complex contract. City Light's rights to the output of Priest Rapids Project are dependent on Grant PUD's load, actual WAPR output and the market price for electricity. The specifics of the Priest Rapids contract have changed over time. Below is a summary of the individual contract "products" as of 2010:

- **Reasonable Portion** (more information is located in Chapter 3)
    - Per FERC License, Grant PUD must sell 30% of the WAPR output at a market price set by a power auction.
    - City Light is entitled to a portion (6.14%) of the revenue from the sale of 30% of the WAPR output after Grant PUD takes its share.
        - Grant PUD can take a portion of the revenue if it estimates it will have unmet load.
    - City Light pays WAPR operating costs relative to the actual percentage of the reasonable portion revenue it receives.
- **Meaningful Priority**
    - City Light can elect to purchase up to a maximum of 3.87% of the WAPR output (however, it is only guaranteed 2.78%).
    - City Light will pay a market price set by a power auction.
    - In 2010 City Light has elected to purchase 20 MW of its Meaningful Priority energy.
- **Conversion Product**
    - City Light is entitled to a small fixed amount of the output of WAPR, which is dependent on Grant PUD's District Reserve Share (70% of WAPR output at critical water).
        - Historically this amount has been a little under 3 aMW.
    - City Light pays WAPR operating costs relative to the size of its conversion product take.

- **Surplus Product**
    - If Grant PUD estimates that its load will be less than its District Reserve Share, additional energy may be available to Purchasers.
    - City Light is entitled to 6.14% of the additional surplus energy.
    - City Light will pay WAPR operating costs relative to its actual take of surplus energy.

Table 4.7.1 presents a comparison of costs of power from 'Priest Rapids' as projected in the 2007-2008 Rate Study and as now projected for 2010. As can be seen, there are substantial changes in the average cost of power and amounts of power for the two periods covered. Since the last Rate Study, Grant County's load has changed, market prices for electricity have changed, and in 2010 City Light has elected to purchase a portion of its Meaningful Priority share. In addition, the contract has been amended to include Wanapum Dam. City Light's election to purchase energy from the Meaningful Priority and Surplus products generates an increase in expected purchased energy of 208,609 MWh compared to what was assumed in the 2007-2008 Rate Study.

The average costs for power in Table 4.7.1 are somewhat misleading since all costs are included but City Light gets some money, rather than energy, from the 'Reasonable Portion' product. Nevertheless, the change in rate shown in that Table is used in decomposing the change in costs since the 2007-2008 Rate Study. Table 4.7.2 is a short synopsis of the costs of the various products associated with the 2010 Priest Rapids contracts with Grant PUD. The average costs there indicate costs for each separate product, especially after netting out the revenue from the 'Reasonable Portion' product.

Table 4.7.1
Priest Rapids

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Priest Rapids	1,628,700	12,441,250	10,812,550
Total MWh	19,805	228,414	208,609
Conversion Product MWh	19,805	21,599	1,794
Other Products MWh	0	206,815	206,815
$/MWh, Total*	82.24	54.47	(27.77)
'07-'08 Tot MWh * Δ Avg Rt			(549,962)
'07-'08 Avg Rt * Δ Tot MWh			147,533
Δ Avg Rt * Δ Tot MWh			(49,817)
Product or Sum	1,628,700	1,176,454	(452,246)

*All costs are included, but City Light receives money from the 'Reasonable Power Revenue' portion of the contract rather than energy. Hence, the $/MWh results do not convey the actual cost of energy.

Table 4.7.2
Details of Priest Rapids Cost for 2010

	Conversion Product	Reasonable Portion	Surplus Product	Meaningful Priority Purchase	Total*
Cost	$370,990	$2,971,146	$517,970	$8,581,144	$12,441,250
MWh	21,599	na	30,156	176,659	228,414
Revenue	na	$8,590,472	na	na	$8,590,472
$/MWh	$17.18	na	$17.18	$48.57	$16.86

*The Average cost ($/MWh) for the entire Priest Rapids contract is calculated by netting out the expected Revenue from the expected expenses and dividing by the MWh.

4.8 SPI (Burlington) Purchase

The Sacramento (CA) Municipal Utility District (SMUD) has a contract to purchase output from the new Burlington renewable biomass generating facility ('Burlington'). Burlington is owned by Sierra Pacific Industries (SPI) and located in Whatcom County (WA). SMUD's Burlington energy needs to be delivered from Washington to California.

City Light entered into a ten-year agreement (August 1, 2007 through July 17, 2017) with SMUD that provides for City Light to:

(a) Provide scheduling and delivery services of up to 15 MW of Burlington energy to SMUD at the California-Oregon Border,

(b) Receive up to 25 MW of winter energy from SMUD in payment for such services, and

(c) Purchase from SMUD all of the new renewable energy and environmental attributes (RECs) associated with the Burlington resource in excess of 15 MW or approximately 3 average megawatts.

City Light received 34,678 MWh in 2009 and expects to receive 26,280 MWh in 2010. This contract was not in place and not contemplated in the 2007-2008 Rate Study. Table 4.8 presents the costs and energy expected for 2010. The average price in the table reflects that the bundled cost of renewable resources (i.e., energy and RECs) is generally higher than expected market prices. The RECs have a market value that is separate from the energy value.

City Council Resolution #30144 (honoring Earth Day 2000, adopted April 10, 2000) proclaims that City Light should meet as much load growth as possible with cost effective energy efficiency and renewable resources. Subsequently, the State enacted Initiative 937 (Chapter 19.285 RCW) that requires utilities to acquire renewable resources.

Table 4.8
SPI (Burlington Project)

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
SPI Purchase (Burlington Project)	0	1,716,407	1,716,407
MWh	0	26,280	26,280
$/MWh, Total	-	65.31	65.31

4.9 IRP Resources (Columbia Ridge Landfill)

IRP Resources is a placeholder category for new resources that may not be officially under contract yet. City Light's Integrated Resource Plan (IRP) provides a strategy for the acquisition of additional generating resources. The 2008 IRP indicated a need for new resources starting in 2009; currently the only resource in this category is the Columbia Ridge landfill gas facility.

City Light has entered into a 20-year agreement for the purchase of power and environmental attributes from the new Columbia Ridge renewable landfill gas generating facility ('Columbia Ridge') located near Arlington, Oregon. Columbia Ridge is owned by WM Renewable Energy, LLC, a subsidiary of Waste Management who operates the Columbia Ridge landfill that accepts solid waste from the City of Seattle.

Columbia Ridge will be able to produce 6.4 MW of electrical output and City Light will purchase the energy in excess of station service and the preparation of the landfill gas or about 5.8 average MW annually. City Light will receive all of the environmental attributes associated with the 6.4 MW of electrical output. This facility is expected to have a capacity factor in excess of 95%.

Table 4.9
IRP (Columbia Ridge Landfill)

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
IRP Resources (Columbia Ridge)	0	2,870,691	2,870,691
MWh	0	50,633	50,633
$/MWh, Total	-	56.70	56.70

Construction of the facility is nearing completion. Test power is expected in late October or early November 2009 with an on-line date expected in late November 2009. City Light expects to receive 50,633 MWh in 2010. Columbia Ridge meets City Light's resource adequacy requirements, is an eligible renewable resource under Washington State's Energy Independence Act (Chapter 19.285 RCW) and complies with Washington State's greenhouse gas emissions rules for base load generation (Chapter 80.80 RCW).

4.10 Water for Power

The cost category called Water for Power includes various costs that are associated with owning and operating the Department's generating resources. The license fees imposed by the Federal Energy Regulatory Commission (FERC) for Land Use and Administrative costs have substantially increased over 2008 costs. The utility is required by law to pay these fees as a condition of the operation of our dams on the Pend Oreille, Skagit and Tolt rivers.

The FERC Administrative fees are for hydropower direct and indirect administrative annual charges by Other Federal Agencies (OFAs) that directly support FERC in hydropower activities. These Other Federal Agencies are US Department of Interior, US Department of Agriculture, US Department of Commerce (specifically, National Marine Fisheries Service), and US Army Corps of Engineers. These OFAs submit detailed costs to FERC and these costs are billed through to the licensees. On March 31, 2009, FERC communicated that the 2009 OFA Administrative costs would represent a 25% increase over 2008 costs. Those higher costs continue on into 2010.

In February 2009, FERC issued a final rule establishing a new fee schedule for federal land use annual charges. For most counties across the U.S., the new schedule adopted a sharply increased per-acre fee, leading to much higher annual charges for most licensees. Section 10(e) of the Federal Power Act required FERC to establish and bill hydro licensees annual charges for several categories of costs, including and recompensing the United States "for the use, occupancy, and enjoyment of its lands and other property." As part of the Energy Policy Act of 2005, Congress directed an update to the Federal Land Policy and Management Act fee schedules to better reflect current land use values. The application of the new land use fee schedule increased City Light's costs from $1,080,922 in 2008 to $4,085,205 in 2009, a substantial increase. Cost estimates for 2010 represent a continuation of these new higher fees.

As a result of legislation in 2007 (SSB 5881), the Washington State Department of Ecology (DOE) fees increased from $29,000 in 2008 to $146,322 in 2009. This is the first time in several decades that these fees have been raised. Cost estimates for 2010, embedded in Table 4.10, represent a continuation of these new higher fees.

City Light has agreements with a number of other entities to pay for storage of water in reservoirs upstream of City Light facilities. For example, City Light's Boundary dam's operation is enhanced because of the operation of storage projects at Albani Falls (run by the US Corps of Engineers), Kerr dam (Montana Power), and the Hungry Horse facility (US Bureau of Reclamation) up-river of its location on the Pend Oreille river. These other entities and City Light are parties to the Pacific Northwest Coordinating Agreement (PNCA). City Light also reimburses Pend Oreille County for encroachment. City Light's Boundary dam's storage reservoir backs up to the tail race of Pend Oreille's Box Canyon dam, decreasing the efficiency of converting that dam's water power to electricity.

Table 4.10
Water for Power

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Water for Power	4,363,317	10,469,557	6,106,241
License and FERC Admin Fee	970,623	3,554,659	2,584,036
PNCA Storage	1,170,600	1,600,730	430,130
Encroachment	1,186,300	1,129,295	(57,005)
Land Rents	1,035,793	4,184,874	3,149,081

4.11 Wheeling

Wheeling is a term that means to transport power across other entities' power lines. City Light might incur wheeling costs as a part of delivering power to customers or in selling on the wholesale market. The table below compares wheeling costs as assumed in the 2007-08 Rate Study and the current forecast. Wheeling costs have generally increased because the overall cost of transmission has increased. Grand Coulee local wheeling has decreased because City Light entered into a long-term transmission agreement for this power, eliminating the need to use wheeling services.

Wheeling costs for the Wind Resources changed for several reasons. In 2004, City Light reserved PacifiCorp transmission for the Stateline Wind Project for use when the Stateline Integration and Exchange Agreement with PacificCorp terminates at the end of 2011. For five years the annual reservation fee was 1/12 of the total yearly amount. Starting in December 2009, City Light must start taking the transmission service and paying the full annual cost. Thus, this cost increased by twelve times. This increase was in accordance with FERC rules and PacifiCorp's tariff, and was recognized in the City Light Ordinance authorizing acquisition of the transmission.

Additionally, the Wind Resources wheeling charge for 2010 included a new PacifiCorp Wind Integration Charge, a charge that would be recovered under PacifiCorp's transmission tariff. It represents the cost of a balancing authority, in this case PacifiCorp, using its own generation to follow the wind up and down within an hour to smooth the wind generation across that hour. BPA has this type of charge and PacifiCorp will have one as well.

Table 4.11
Wheeling

	2007-2008 Rate Study	Current Forecast 2010	Δ = 2010 - '07-'08 Rt Study
Wheeling	39,725,326	48,159,603	8,434,277
Boundary	18,786,388	20,095,029	1,308,641
South Fork Tolt	380,100	408,444	28,344
Box Canyon to Seattle	0	235,719	235,719
Priest Rapids	1,288,645	1,394,670	106,025
Grand Coulee (BPA)	1,270,495	1,375,026	104,531
Grand Coulee (Local)	994,050	148,078	-845,972
Lucky Peak (BPA)	1,814,993	1,964,323	149,330
Lucky Peak (Local)	1,130,600	2,243,103	1,112,503
Wind Resources	701,300	5,959,330	5,258,030
NCPA Exchange	653,398	707,156	53,758
BPA Firm Power	11,797,457	12,768,102	970,645
Power Market Purchases	0	322,279	322,279
Other Wheeling Purchases	907,900	538,343	-369,557

Chapter 5 - Cash to Operations

5.1 Introduction

Cash to Operations includes costs associated with operating and maintaining:

- Power Production Facilities and Services
- Transmission Facilities
- Distribution Facilities and Services
- Customer Accounting and Services
- Conservation (non deferred)
- Administrative and General Activities

This chapter begins with an analysis of Cash to Operations associated with the budget for 2010 endorsed in 2008, called the Endorsed 2010 Budget. Each Cash to Operations category has a separate section dedicated to explaining the major changes from the 2007-2008 Rate Study to the forecast of the budget for 2010 endorsed in 2008. The last section of the chapter introduces City Light's proposed changes to 2010 Cash to Operations and compares the final proposed 2010 Cash to Operation value with what was assumed in the 2007-2008 Rate Study.

City Light projected that in 2010 cash operating expenses associated with the budget for 2010 endorsed in 2008 would be about $61.0 million or 40% higher than the average amount projected when rates were set in 2007-2008 (See Table 5.1). Since the time 2007-2008 rates were set, City Light experienced significant cost increases in many areas of its core operational programs and services. In addition, City Light adopted new programs and expanded existing programs to support the Utility's mission of providing reliable energy and excellent customer service. Another significant reason why the difference between the budget for 2010 endorsed in 2008 and the 2007-2008 Rate Study is so large is that there were a number of planned cost reductions for 2007 and 2008 that were assumed in the previous rate study but never adopted into the 2007-2008 budgets, which formed the foundation for the 2009 and 2010 budgets endorsed in 2008.

Table 5.1
Change in Cash to Operations Between the 2007-2008 Rate Study and the Forecast Associated with the Endorsed 2010 Budget

Cash Flow	Last Rate Study 2007 & 2008	Forecast Endorsed 2010 Budget	Change	Percentage Change
Cash to Operations	**153,456,727**	**214,428,881**	**60,972,155**	**40%**
Cash to Production	23,971,906	34,524,346	10,552,440	44%
Cash to Transmission	5,788,367	9,105,905	3,317,538	57%
Cash to Distribution	41,499,637	64,307,701	22,808,065	55%
Cash to Conservation	2,455,453	8,740,896	6,285,444	256%
Cash to Customer Accounting	26,251,817	31,561,831	5,310,015	20%
Cash to Administration	53,489,548	66,188,202	12,698,654	24%

The base 2010 forecast for each Cash to Operations category was taken from 2008 actual expenses (adjusted for any non-reoccurring expenses) and increased with the rate of inflation (2.5% in 2009 and 2.4% in 2010). In addition, the forecast was adjusted for program and service changes approved in the budget for 2010 endorsed in 2008, which were approximately $14.5 million net of reductions.

City Light's Financial Forecast of Cash to Operations is itemized by the FERC accounting categories used by City Light to report its financial performance so that the Financial Forecast can be compared to actual financial results. The FERC accounting categories do not always have a direct relationship to City Light's Budget Categories. The Financial Forecast that supports the Revenue Requirement analysis requires assumptions about where certain budget categories will get recorded. In summary, there is not a simple or direct cross-walk between budget categories and Financial Forecast and accounting categories.

The tables in the following sections show the major budget changes the year they first occurred and how they were carried forward. Thus, a program adopted in 2007 carries through to 2010, unless otherwise indicated. It is important to note that these program changes were all reviewed and adopted through the City's budgeting process.

The 2007-2008 Rate Study assumed an average Consumer Price Index (CPI) for 2007-2008 of 208.5. The actual CPI in 2007 and 2008 turned out much higher (210.2 and 219.7, respectively). Thus, the inflation line in the following tables captures this difference in CPI and can be used as a proxy to explain some of the increases in O&M costs in those years. In addition, 2009 and 2010 CPI forecasts have been used to extend the inflation increases to 2009 and 2010.

In each table, the last line, "Cash to Residual," includes all other Cost to Operations changes that were not due to the assumed inflation or identified program changes. Examples may include a true-up to actual expenditures, or baseline adjustments to the budget that differ from the inflation assumptions used.

The "Program Reductions in 2009" line refers to the O&M reductions approved in the 2009 Adopted Budget and the budget for 2010 endorsed in 2008. These are different from the $20.6 million single-year reduction City Light made to the O&M budget in early 2009 to attempt to make up for some of the shortfall in net wholesale revenue. These mid year cuts are a major reason why the "Cash to Residual" value in a number of the categories is negative in 2009.

5.2 Production

Cash to Production includes expenses associated with the operation and maintenance of City Light's owned hydroelectric plants. The majority of this expense is for the Utility's facilities on or near the Skagit River (Ross, Diablo, Gorge and Newhalem plants) and Pend Oreille River (Boundary plant). City Light also owns and operates two smaller hydroelectric facilities, South Fork Tolt and Cedar Falls, which are both located a little east of City Light's service territory.

Production expenses also include the cost of the system control center, power marketing activities and greenhouse gas mitigation.

Production expenses in the forecast associated with the budget for 2010 endorsed in 2008 increased $10.6 million or 44% above the average amount projected in the 2007-2008 Rate Study. Table 5.2 shows a list of major changes in programs and services that have been adopted since the 2007-2008 Rate Study. A more detailed description of each major budget initiative is available in Appendix 6.

Table 5.2
Changes in Cash to Production

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Production	**23,971,906**	**26,582,606**	**30,435,496**	**28,260,132**	**34,524,346**
Difference from 2007-2008 Rate Study	-	**2,610,700**	**6,463,590**	**4,288,226**	**10,552,440**
Major Reasons for Difference					
Inflation		207,159	1,291,081	1,922,621	2,554,391
Wage settlement above inflation		-	-	577,558	577,558
Construction Management Services (14 positions)		-	1,787,445	1,787,445	1,787,445
Integrated Resource Management		-	298,255	298,255	298,255
Boundary Relicensing		1,200,000	1,200,000	1,200,000	1,200,000
Boundary Sluice Gate O&M		-	-	32,000	581,000
Diablo Tailrace Dredging and Trash Rack Cleaning		-	-	150,000	1,850,000
Skagit & Boundary - Vessel Maintenance		-	-	240,000	390,000
Skagit Water System Improvement		-	-	220,000	165,000
Program Reductions in 2009		-	-	(750,000)	(750,000)
Cash to Residual		1,203,541	1,886,809	(1,389,653)	1,898,791

* Per Endorsed 2010 Budget

5.3 Transmission

Transmission expenses include the cost of operating and maintaining City Light's transmission facilities. City Light's principal transmission line transmits electricity from the Skagit Project to the City Light service territory. 2010 transmission expenses were expected to be $3.3 million higher than the amount assumed when rates were set in 2007-2008. This increase primarily reflected rising labor and materials costs for ongoing maintenance of transmission property and equipment. It also included some increased expenditures for security and safety as mandated by North American Electric Reliability Corporation (NERC) standards. Table 5.3 lists the changes in Cash to Transmission. One of the reasons why the Cash to Residual line is so large is because

Table 5.3
Changes in Cash to Transmission

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Transmission	**5,788,367**	**6,809,723**	**8,389,958**	**8,852,064**	**9,105,905**
Difference from 2007-2008 Rate Study		**1,021,356**	**2,601,591**	**3,063,697**	**3,317,538**
Major Reasons for Difference					
Inflation		50,022	311,750	464,245	616,795
Cash to Residual		971,334	2,289,841	2,599,452	2,700,743

* Per Endorsed 2010 Budget

none of the major budget changes were allocated to Transmission. However, it is expected that a share of some of the budget initiatives fully allocated to other categories have impacted transmission expenses in 2007 and 2008 and will continue to do so in 2009 and 2010.

5.4 Distribution

Distribution accounts for the largest increase in operating expenditures. Distribution expenses include the direct expenses of operating and maintaining substations, power lines, line transformers, poles, service connections, meters, and streetlights. City Light projected distribution expenses associated with the budget for 2010 endorsed in 2008 would be $22.8 million or 55% above what was projected in the 2007-2008 Rate Study. Table 5.4 shows a list of major program and service changes that have been adopted since the 2007-2008 Rate Study. A more detailed description of each major budget initiative is available in Appendix 6.

Table 5.4 Changes in Cash to Distribution

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Distribution	**41,499,637**	**53,753,780**	**60,699,360**	**58,167,623**	**64,307,701**
Difference from 2007-2008 Rate Study	**-**	**12,254,144**	**19,199,724**	**16,667,987**	**22,808,065**
Major Reasons for Difference					
Inflation		358,630	2,235,091	3,328,400	4,422,106
Wage settlement above inflation		-	-	1,441,517	1,441,517
Skilled Trades/Lineworker Positions (63 Positions)		-	4,562,775	4,562,775	4,562,775
Apprenticeship Program		400,000	400,000	800,000	800,000
Asset Management		-	2,516,000	2,516,000	2,516,000
Asset Management - Pole Testing and Treatment		-	-	1,050,000	1,050,000
Construction and Electrical Material Increase		-	-	1,600,000	1,600,000
Field System and Substation O&M		-	-	500,000	500,000
Fire Resistent Clothing		-	-	900,000	250,000
NERC and Regulatory Compliance		-	-	950,300	935,300
NERC Compliance		775,916	775,916	775,916	775,916
NERC Cyber Security Compliance		-	500,000	500,000	500,000
CSED Overtime Increase				2,000,000	2,000,000
Vegetation Management		4,300,000	4,300,000	4,300,000	4,300,000
Program Reductions in 2009				(1,050,000)	(1,050,000)
Cash to Residual		6,419,598	3,909,941	(7,506,921)	(1,795,550)

* Per Endorsed 2010 Budget

Back in the early 2000s City Light delayed a large amount of distribution maintenance because of the 2000-2001 Energy Crisis. In the past few years, City Light has increased its budget to catch up to the level of distribution operations and maintenance (O&M) needed to keep its electrical system reliable. The majority of the increase in distribution costs were a result of the adoption of these 'catch-up' programs and services. In addition, City Light experienced significant unplanned increases in distribution overtime over the past few years. Much of this increase was due to higher work loads and restricted operating hours for certain projects requiring work to be done on overtime. However, City Light has adopted management controls to help contain overtime expenditures.

5.5 Conservation (Direct Expenses)

There are two types of conservation expenditures in City Light's budget and forecast: direct conservation expenditures and deferred conservation expenditures. Direct conservation expenditures include costs for administration, planning, marketing, and customer services for all conservation programs. These direct conservation expenditures impact the revenue requirements in the year in which they are incurred. Deferred conservation expenditures are treated like capital expenditures and impact revenue requirements in future years through requirements to cover debt service (See Chapter 16 for deferred conservation expenditures). Table 5.5 shows that City Light projected direct conservation expenses associated with the budget for 2010 endorsed in 2008 to be $6.3 million or 256% higher than the average amount assumed in the 2007-2008 Rate Study. This large increase reflected City Light's investment in conservation as its first choice energy resource. In 2008 City Council adopted City Light's 5-Year Conservation Plan that accelerated annual conservation additions from 7 aMW in 2007 to 15 aMW in 2012.

Table 5.5
Changes in Cash to Conservation

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Conservation	**2,455,453**	**2,690,207**	**4,311,889**	**3,920,552**	**8,740,896**
Difference from 2007-2008 Rate Study		**234,755**	**1,856,437**	**1,465,100**	**6,285,444**
Major Reasons for Difference					
Inflation		21,219	132,246	196,935	261,647
Wage settlement above inflation		-	-	99,700	99,700
Conservation 5-Year Plan (Only O&M Portion)		-	-	2,800,000	4,200,000
Energy Efficiency Fund (O&M Portion Only)		-	-	182,000	184,000
Program Reductions in 2009		-	-	(270,000)	(270,000)
Cash to Residual		213,535	1,724,191	(1,543,535)	1,810,096

* Per Endorsed 2010 Budget

5.6 Customer Accounting

Customer Accounting expenses include the direct expenses for reading meters, billing customers, providing information to customers, and maintaining customer records. These expenses were forecasted to remain close to their historical levels. City Light projected Customer Accounting expenses to be $5.3 million or 20% higher than what was forecasted when 2007-2008 rates were set. Table 5.6 shows a list of major Customer Accounting program and service changes that have been adopted since the 2007-2008 Rate Study. A more detailed description of each major budget initiative is available in Appendix 6.

Table 5.6
Changes in Cash to Customer Accounting

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Customer Accounting	**26,251,817**	**27,179,981**	**28,673,329**	**29,840,055**	**31,561,831**
Difference from 2007-2008 Rate Study		928,165	2,421,513	3,588,239	5,310,015
Major Reasons for Difference					
Inflation		226,862	1,413,873	2,105,477	2,797,333
Wage settlement above inflation		-	-	300,000	300,000
Call Center Cost Increase (SPU payment)		-	-	1,659,000	1,659,000
CCSS Technology Lift		-	-	500,000	-
Program Reductions in 2009		-	-	(730,000)	(730,000)
Cash to Residual		701,303	1,007,640	(246,239)	1,283,681

* Per Endorsed 2010 Budget

5.7 Administration and General

Administration and General expenses (A&G) include the direct expenses for administration, planning, office supplies, building rents, maintenance of general plant, services provided by the Executive Services Department, injury and damage claims, cleanup of toxic materials, and research and development. City Light projected 2010 A&G cash expenses associated with the budget for 2010 endorsed in 2008 would be $12.7 million or 24% higher than what was forecasted in the 2007-2008 Rate Study. Table 5.7 shows a list of major A&G program and

Table 5.7
Changes in Cash to Administration and General

	Rate Study 2007 & 2008	Actual 2007	Actual 2008	Forecast 2009	Forecast 2010*
Cash to Administration	**53,489,548**	**64,379,996**	**59,892,384**	**64,357,991**	**66,188,202**
Difference from 2007-2008 Rate Study		**10,890,448**	**6,402,836**	**10,868,443**	**12,698,654**
Major Reasons for Difference					
Inflation		462,244	2,880,845	4,290,028	5,699,724
Wage settlement above inflation		-	-	1,000,000	1,000,000
Accounts Payable – Workload Issues		-	-	60,000	60,000
Climate Program		-	-	900,000	900,000
City Cost Allocation Increase		1,600,000	1,600,000	1,600,000	1,600,000
Duwamish Cleanup		2,000,000	2,000,000	2,000,000	2,000,000
Greenhouse Gas Offsets		-	-	872,000	872,000
Low-Income Assistance		-	-	200,000	200,000
Rent/Space Lease		1,600,000	1,600,000	2,600,000	2,600,000
Risk Management - Annual Audit		-	-	180,000	180,000
Safety Compliance Items and Audits, HRBU		-	-	240,000	390,000
Program Reductions in 2009		-	-	(2,270,000)	(2,270,000)
Cash to Residual		5,228,204	(1,997,009)	(1,303,585)	(533,069)

* Per Endorsed 2010 Budget

service changes that have been adopted since the 2007-2008 Rate Study. A more detailed description of each major budget initiative is available in Appendix 6. Approximately half of the $12.7 million dollar difference is estimated to be caused by inflation.

5.8 Proposed Changes to the Budget for 2010 Endorsed in 2008

City Light is proposing significant reductions in Cash to Operations relative to the budget for 2010 endorsed in 2008 to mitigate the size of the 2010 rate increase. Specifically, City Light is planning to cut roughly $24 million in O&M expenses from the budget for 2010 endorsed in 2008. City Light is also proposing $11.3 million of additional budget authority for new spending. Therefore, the net proposed decrease for Cash to Operations is $12.7 million. Table 5.8 lists the proposed changes for each category.

Table 5.8
City Light Proposed Adjustments to 2010 Cash to Operations

2010 Proposed Additions to Cash to Operations (BIPS)	**11,259,893**
Production	
Self-Build Power Marketing, Risk Management and Settlements	640,577
Fleet Management Support Staff	181,650
Distribution	
Streetlight Group Re-Lamping Program	923,080
Asset Management and Work Management Program	2,174,753
Reimbursable Cell Site and Pole Attachment Construction	1,470,602
LED Streelight Conversion Program	26,341
CSED Feeder Maintainance	1,500,000
Crane Safety Program	622,101
NERC Required Transmission and Distribution Planning	132,290
Conservation	
Energy Efficiency Community Block Grant - add to Federal Stimulus	1,050,000
Customer Accounting	
Security Services	276,450
Administration	
Baseline Adjustments	499,402
Technical Adjustments - Liability Claims	1,762,647
2010 Proposed Cuts in Cash to Operations	**23,950,528**
Production	5,805,210
Distribution	8,195,262
Conservation	799,103
Customer Accounting	1,455,054
Administration	
Financial Services BU	1,576,909
Human Resources BU	620,858
Superintendent's BU	324,776
Other	
Benefits Related to Eliminated/Deferred Positions	1,757,803
Cap 2010 COLA at 2.0%	1,612,354
Furloughs	1,803,200
Proposed Change to 2010 Cash to Operations, Net	**(12,690,635)**

The proposed reductions in operating expenses (i.e., reduced cash to operations) are in the following areas and include 70 positions (or 68 full-time equivalent positions):

- **Production**
  - Maintenance of generating facilities
  - Machine shop
  - Engineering resources and facility support
  - Travel and contracting.
- **Distribution**
  - Reduced Production Scheduling and Warehousing Program
  - Reduced Administration Staff
  - Reduced Vegetation Management
  - More Efficient Crew Work Assignment
- **Conservation**
  - Scale Down the 5-Year Plan
- **Customer Accounting**
  - Account Executive Office
  - Administration Staff
  - Contracting
  - Training, Travel and Supplies
- **A&G**
  - Human Resource Services
  - Internal Communications and Advertising
  - IT operations, applications, security and support
  - Strategic Planning
  - Accounting Services
  - Administration Support

Table 5.9 shows the proposed Cash to Operations along with the difference from what was projected in the 2007-2008 Rate Study. With the proposed budget reductions, the difference is now $48 million (as compared to the $61 million shown in Table 5.1).

Table 5.9
Change in Revenue Requirements between 2007-2008 Rate Study and 2010 Proposed Budget

Cash Flow	Rate Study 2007 & 2008	Forecast 2010 Proposed Budget	Change	Percentage Change
Cash to Operations	**153,456,727**	**201,738,246**	**48,281,520**	**31%**
Cash to Production	23,971,906	28,342,057	4,370,151	18%
Cash to Transmission	5,788,367	9,105,905	3,317,538	57%
Cash to Distribution	41,499,637	61,564,393	20,064,757	48%
Cash to Conservation	2,455,453	8,545,134	6,089,682	248%
Cash to Customer Accounting	26,251,817	29,413,637	3,161,821	12%
Cash to Administration	53,489,548	64,767,120	11,277,572	21%

Chapter 6 - Cash to Rate Discounts

6.1 Cash to Rate Discounts

The Department offers utility rate assistance to low-income customers who receive Supplemental Security Income and customers who are at or below 70 percent of the Washington State median income. The median income is computed annually by the State or City on the total household income. Utility rate assistance is a 60 percent discount on utility bills. If customers do not have bills in their names, they get a credit on another utility bill.

In 2009, the Mayor's Office for Senior Citizens implemented an aggressive outreach program to increase customer participation in the Utility Discount Program. As shown in Table 6.1, the average number of low-income customers accepting rate assistance is projected to increase from 12,416 projected for 2007-2008 in the 2007-2008 Rate Study to 13,000 projected for 2010 in the current Rate Study. The Energy Delivered to Assisted Residential Customers is projected to decrease slightly. Cash to Rate Discounts is expected to increase from $5.6 million projected for 2007-2008 in the 2007-2008 Rate Study to $6.1 million projected for 2010 in the Current Rate Study. This increase of $0.5 million comes from the projected increase in retail rates. Low-income customers will continue to pay 40 % of the regular residential rates

6.2 Cash to Other Low-Income Assistance Programs

In addition to rate discounts, the utility provides other assistance to Low-Income Customers. Cash to these programs is included in other parts of the financial forecast. These are itemized on the bottom of Table 6.1 and described here.

6.2.1 Cash to Service and Administrative Fee Waivers

Customers receiving Low-Income Assistance do not pay trouble call charges and account change fees. Total cash to these two waivers is expected to remain at about the $38,000 projected for 2007-2008 in the 2007-2008 Rate study. The split between the two types of waivers is shown on the bottom of Table 6.1. Cash to Account Change Fee Waivers is considered a deduction from the Cash from All Other Sources described in Chapter 3. Cash to Trouble Call Fee Waivers is included in Cash to Operations described in Chapter 5.

Table 6.1
Cash to Rate Discounts

	2007-2008	2010	Diff
Cash from Assisted Residential Customers ($)			
Before Discounts	9,258,000	10,239,573	981,573
After Discounts	3,706,983	4,153,266	446,283
Cash to Rate Discounts	5,551,017	6,086,307	535,290
Average Assisted Residential Rate ($/MWh)			
Before Discounts	63.92	71.75	7.83
After Discounts	25.59	29.10	3.51
Discount	38.32	42.65	4.32
Percent Discount	60.0%	59.4%	
Energy Delivered to Assisted Residential Customers (MWh)	144,846	142,711	(2,135)
Number of Assisted Residential Customers	12,416	13,000	584
Cash to Other Low-Income Assistance Programs	472,280	780,362	308,082
Cash to Emergency Low-Income Assistance	251,507	266,502	14,996
Cash to Waivers of Trouble Call Charges	1,083	1,154	72
Cash to Waivers of Account Change Fees	37,274	37,121	(153)
Cash to Administration of Low-Income Assistance Programs	182,418	475,585	293,168

6.2.2 Cash to Emergency Low-Income Assistance Program (ELIA)

This program was established by Ordinance 112637 in December 1985. For customers in a crisis situation who have received a 24-hour shut-off notice, the Emergency Low-Income Assistance Program (ELIA) pays up to 50 percent of a customer’s delinquent bill up to a maximum of $200. Customers must have already received funds from the federally funded and federally administered Energy Assistance Program (EAP). Customers can receive ELIA funds only once a year. Cash to ELIA is expected to increase slightly from $251,507 projected for 2007-2008 in the 2007-2008 Rate Study to $266,502 projected for 2010 in the Current Rate Study. Cash to ELIA is considered a deduction from the Cash from All Other Sources described in Chapter 3.

6.2.3 Cash to Administration of Low-Income Assistance Programs

The Human Services Department - Mayor's Office for Senior Citizens (MOSC) - administers the Low-Income Rate Assistance Programs and Project Share.

Project Share helps City Light customers with delinquent bills who have received a 24-hour shut-off notice. Project Share is funded with public donations. Since the funds are not public funds, the income eligibility can be higher than the 70% of Washington State median income with a waiver for customers under hardship circumstances such as catastrophic illness. To receive help, customers must have exhausted all other sources of help and must demonstrate need. The maximum amount customers can receive is $500 in a calendar year.

Cash to Administration of Low-Income Assistance Programs is expected to increase from $182,418 projected for 2007-2008 in the 2007-2008 Rate Study to $475,585 projected for 2010 in the Current Rate Study. This increase reflects an aggressive outreach program to increase customer participation in these programs. Cash to Administration of Low-Income Assistance Programs is included in Cash to Operations discussed in Chapter 5.

Chapter 7 - Cash to Uncollectable Revenue

Every year, a portion of past-due accounts receivable for revenues from both retail and wholesale customers are never received, despite collection efforts, and must be written off as uncollectable. Uncollectable revenue has been declining during the past couple of years, thanks to a variety of initiatives that include improved collection techniques, stronger efforts to keep customer contact information in the billing system up-to-date so that customers can be contacted sooner when bills become delinquent, new billing and payment methods such as electronic billing and online payment, and improved monitoring of the credit quality of current and potential wholesale power customers. Uncollectable revenue is projected to remain stable at its recent level, which is equal to around 0.9% of revenue from energy sales to retail customers. This is a reduction from over 1% in 2005 and 2006. The $5.3 million currently projected for 2010 is $0.1 million lower than the average forecast for 2007-2008 during the previous rate-setting process despite higher projected retail energy sales revenue.

Chapter 8 - Cash to State Taxes and Franchise Payments

8.1 Overview

The Department recognizes taxes and contract payments as operating expenses. The major taxes paid by City Light are revenue taxes paid to the City of Seattle and the State of Washington. Taxes paid to the City of Seattle are subordinate to debt service. Therefore, they are in a different cash flow category than Cash to State Taxes and Franchise Payments. They are discussed further in Chapter 10, which includes the rationale for their separate treatment. However, computation of City Taxes has similarities to computation of State taxes, so the calculation of City Taxes is also discussed here.

Besides explicit tax payments, the Department also makes payments to counties in which City Light resources are located. These payments are for a variety of public services, such as fire and police protection, schools, and road maintenance. City Light also makes payments to suburban cities, as agreed in franchises negotiated with these cities. Other taxes include city and state business taxes.

Table 8.1 (next page) presents data on all taxes and related costs as projected for the average of the 2007-2008 Rate Study and as now projected for 2010. For cash flow purposes, the summary total for taxes and related costs that are a component of expenditures that reduce Cash Available for Debt Service Coverage is in the row titled **Cash to State Taxes and Franchise Payments**. City Taxes are also discussed briefly here because their methodology of computation is similar to the methodology for computing State Taxes. City Taxes are discussed separately in Chapter 10.

8.2 State and City Taxes

The Revenue Tax Base in the section on Factors Affecting City Occupation and State Public Utility Taxes in the table should, perhaps, be labeled ‘Gross’ Revenue Tax Base. Not all of what might be considered the ‘Gross’ Revenue Tax Base is subject to State and City taxes. Thus, an adjustment is needed to create what might be called a ‘Net’ Revenue Tax Base. This concept is created as the product of the Revenue Tax Base and (1 minus percent revenue deductible from either State or City Tax). Estimates of revenue tax payments, then, are created by multiplying this term by the appropriate State or City Tax rate. It turns out that change in the gross revenue is the dominant term in explaining the increase in the City and State taxes and this change, in turn, is dominated by the change in retail rates between what is projected in 2010 and what was expected for 2007-2008 in the 2007-2008 Rate Study.

The State and City taxes in the table equal the revenue (also known as Occupation and Public Utility) taxes, as just described, plus Business taxes. Business taxes to the state and to the City have been relatively steady and are in the $0.1 million range for the State and $0.01 million range for the City. State taxes also include some very minor ‘Other’ taxes that have hardly changed. Overall, revenue taxes account for the vast majority of State and City tax payments.

Table 8.1
Taxes

	2007-2008 Rate Study	Current Forecast 2010	Δ = Current - '07-'08 Rt Study
Cash to Total Taxes	**61,388,240**	**67,525,892**	**6,137,652**
Seattle City Taxes	33,224,667	37,182,253	3,957,586
City Business	10,767	11,845	1,078
City Occupation	33,213,901	37,170,408	3,956,507
Cash to State Taxes and Franchise Payments	**28,163,573**	**30,343,639**	**2,180,066**
State Taxes	21,783,711	23,247,993	1,464,283
State Business	100,507	110,574	10,068
State Public Utility	21,678,455	23,132,193	1,453,739
Other	4,749	5,225	476
Payments to other government entities (excluding franchise pymts)	2,415,274	2,562,177	146,903
King County Surface Water Management Fees	144,377	144,377	0
Whatcom County Contract Pmts	863,918	916,443	52,525
Pend Oreille County Contract Pmts	1,296,638	1,383,783	87,145
Renton Business Tax	84	92	8
Payments to Concrete School District	110,257	117,482	7,225
Payments to Franchises	3,964,588	4,533,469	568,881
Payments to Shoreline	1,246,706	1,650,270	403,565
Payments to Burien	717,023	762,702	45,680
Payments to Lake Forest Park	251,620	267,650	16,030
Payments to Tukwilla	1,624,589	1,720,254	95,666
Payments to Sea-Tac	124,652	132,593	7,942
Factors Affecting City and State Taxes			
Pct Revenue Deductible from City Tax	1.99	2.50	0.51
Pct Revenue Deductible from State Tax	1.97	6.00	4.03
City Revenue Tax Rate Percent	6.14	6.00	-0.14
State Revenue Tax Rate Percent	3.87	3.87	0.00
Revenue Tax Base including CIAC	570,981,221	635,391,593	64,410,373
Revenue Tax Base excluding CIAC	551,926,346	608,797,350	56,871,005
Contributions in Aid of Construction	19,054,876	26,594,243	7,539,368

(#) Includes Contributions in Aid of Construction

In 2006, a reading of the tax law suggested that cash from Contributions In Aid of Construction (CIAC) should be excluded from the revenue tax base when computing the revenue tax payment to the City, though that cash should be included in the revenue tax base when computing the revenue tax payment to the State. Subsequently, a clarification has occurred that indicates cash from CIAC should be in the revenue tax base for computing both State and City taxes. Hence, City taxes have had an upwards push compared to the 2007-2008 Rate Study because of this change in computation of City revenue taxes.

Other factors affecting the City Occupation Tax are the fraction of the Gross Revenue that is subject to City taxes, and the City tax rate itself. Similar reasoning, though with different factors, also controls the computation of the State Public Utility Tax. It is possible to deconstruct the changes in total City and State taxes into all their constituent components, but the conclusion in each case is that changes in gross revenue are the prime determinant of changes in the tax payments and the main determinant of change in gross revenue is the change in rates between what was projected for the 2007-2008 Rate Study and what is projected for the 2010 Rate Study.

8.3 Other Related Expenses

Payments to Counties and Schools. Contracts for Whatcom County, where the Skagit Projects are located, and Payments to Pend Oreille County, where the Boundary project is located, both allow for annual increases to account for inflation. Payments for 2010 to these entities reflect this inflation factor.

In addition, City Light makes payments to the Concrete School District (located in Whatcom County), which provides career counseling, bus transportation to after school events and night school, and other services to City Light staff and family members residing at the Skagit. These payments are about $0.1 million annually.

Payments to Suburban Cities. City Light also makes payments to suburban cities with which it has negotiated franchise agreements to construct, operate, replace, and repair the electric and light system to serve those areas. These payments are made to the cities in return for their agreement not to exercise their rights to establish their own municipal utilities and to acquire City Light's distribution property within their limits.

Under the terms of franchise agreements signed in 1998,1999 and 2002, City Light makes monthly payments to the cities of Shoreline, Burien, Lake forest Park, SeaTac and Tukwila in amounts equal to 6.0% of the revenue attributed to the energy component of rates charged to customers residing within those cities. Under a franchise agreement with the City of Tukwila signed in 2002, the Department paid Tukwila monthly amounts equal to 4% of total revenue billed to customers in Tukwila from March 1, 2003, through December 31, 2004, 5% of revenue in calendar years 2005 and 2006, and now pays 6% of revenue through the end of the franchise in 2018. Under the franchise agreement with Shoreline, the Department started paying 6% of the total revenue as of April 2009.

Payments to suburban cities consistent with the franchises are projected to increase from around $3.9 million in 2007/2008 to around $4.5 million in 2010. Payments to the suburban cities increase when retail rates increase.

Other Taxes and Payments. This forecast includes State and City business taxes not based on revenues and payments to King County for surface water management fees. The former were discussed above in Section 8.2. The latter expenses are not projected to increase.

On the whole, these other tax-related and contract-related payments are not expected to increase significantly in 2010 relative to their expected costs in the 2007-2008 Rate Study.

Chapter 9 - Cash Available for Debt Service Coverage

Cash available for debt service coverage is the amount of annual revenue, net of qualifying expenses, that is available to pay debt service. The target amount for cash available for debt service coverage is directly affected by City Light's guiding financial policy that specifies a debt service coverage ratio that should be used for planning purposes. Hence, the financial policy is critical in determining the Department's revenue requirement for rate-setting purposes.

City taxes are exempt from this calculation, as debt payments must be paid before city taxes. The cash available for debt service coverage, given the cash sources and uses described in the previous chapters, determines the amount of retail revenue that must be collected to meet City Light's targeted debt service coverage. As discussed in the summary, in 2010 City Light is proposing to reduce its targeted debt service coverage from 2.0 to 1.6. Debt service in 2010 is projected to be $150.7 million (see Chapter 12 for more information). Therefore, to meet its 2010 targeted debt service coverage of 1.6, City Light must adjust retail revenue so that the annual revenue net of qualifying expenses is $241.1 million ($150.7 million * 1.6).

Table 9.1 compares Cash to Debt Service Coverage between the 2010 forecast and the 2007-2008 Rate Study. Lowering the debt service coverage target to 1.6 reduces the amount of retail revenue needed to meet this target and, thus, lowers the percentage of the rate increase. However, an increase in retail revenue is still required to cover the shortfall caused by large increases in operating expenses and lower wholesale revenue.

Table 9.1
Cash to Debt Service Coverage

	Last Rate Study 2007 & 2008	Forecast 2010	Change	Percentage Change
Cash Available for Debt Service	297.1	241.1	-56.0	-19%

Chapter 10 – Cash to City Taxes

City Taxes were first discussed in Chapter 8 that surveyed all taxes and related payments. That chapter presented the data on City Taxes, along with the other taxes and related costs, as estimated in the 2007-2008 Rate Study and forecast for 2010. The reason for raising this topic again is that the cash used to pay City Taxes is in a different category than the other taxes and related costs which are considered primary, direct operating costs. Cash available for paying City Taxes is available, first, for paying debt service. Cash available for paying City Taxes, therefore, does not directly affect revenue requirements for setting retail rates.

City Light is in the electricity business, one of the most capital intensive businesses in the world. The expensive capital equipment is paid for over an extended period, approximating the useful life of the equipment. This means that at any point in time, City Light has a large amount of debt outstanding that must be serviced each year. The bond official statements that explain the terms under which money the Department borrows must be repaid note that the Seattle City Charter does not permit the Department to pay taxes to the City's General Fund "until ample provision has been made for the servicing of the debts and obligations of the utility for necessary betterments and replacements for the current year." This is equivalent to saying that City taxes take a junior lien to debt service. Thus, the cash available for debt service is used, first, to pay debt service costs, and then the residual is available to pay City taxes.

The Department's current financial policies require that the Department plan to have sufficient cash to cover debt service by a factor of 2.0. Since current debt service is in the range of $145-$155 million and City Taxes are in the $30-$40 million range, this means, that, practically speaking, there is more than adequate cash to pay City Taxes. This conclusion is true even with the current proposal to decrease debt service coverage to 1.6 for the year 2010.

Table 10.1 recapitulates the data on City Taxes embedded in Table 8.1 in Chapter 8. That chapter discussed the differences between what was projected in the 2007-2008 Rate Study and what is now projected for 2010. That chapter also explained that the anticipated increase in taxes in 2010 compared to the 2007-2008 period is primarily attributable to the projected increase in retail rates, and, hence, increase in the retail tax base in 2010.

Table 10.1
Cash to Pay City Taxes

	2007-2008 Rate Study	Current Forecast 2010	Δ = Current - '07-'08 Rt Study
Seattle City Taxes	33,224,667	37,182,253	3,957,586
City Business	10,767	11,845	1,078
City Occupation	33,213,901	37,170,408	3,956,507

Chapter 11 - Cash to All Other Purposes

Besides City Taxes, there are other uses of cash that do not directly affect revenue requirements for setting rates in the proposed rate year. Cash to All Other Purposes (excepting the items discussed in Chapter 16) is another example. Table 11.1 illustrates these other uses for the period 2009 to 2012 to provide information on the outlook for these uses for the next several years. The higher these are, the more pressure there might be to increase borrowing and thereby increase future debt service requirements and, hence, increase future rates.

Table 11.1
Cash to All Other Purposes

	2009	2010	2011	2012
Cash to All Other Purposes	15,376,550	(784,548)	9,488,864	9,759,743
equals				
Plus Cash to Materials and Supplies	595,291	621,482	636,182	651,229
Plus Cash to Accounts Receivable	7,781,259	(1,406,030)	8,852,682	9,108,514
Minus Cash to Accounts Payable	(7,000,000)	0	0	0

Cash to Material and Supplies is the addition to materials and supplies stored in warehouses. These materials and supplies are waiting to be used in capital and maintenance projects. It is assumed that the balance of materials and supplies suspended in warehouses will increase at the rate of inflation.

The Accounts Receivable balance is the cash earned but not yet received from Customers. The **Cash to Accounts Receivable** is the increase in this balance. The current forecast for 2009 is expecting the increase in Accounts Receivable observed through July of 2009 will continue for the rest of the year 2009. This increase may be the result of customers delaying payment on their bill to help compensate for problems they are encountering in the economic recession. A reversal is expected in 2010. Additions in 2011 and 2012 are the result of load growth and rate increases planned for those years. Load growth expands the balance of energy delivered not yet billed. Higher rates increase the value of the balance of energy delivered not yet billed and the value of the bills outstanding.

The Accounts Payable balance is the cash obligated but not yet paid to employees and suppliers. The **Cash to Accounts Payable** is the increase in this balance. The current forecast for 2009 is expecting the decrease in Accounts Payable observed through July of 2009 will continue for the rest of the year 2009. No additions to Accounts Payable are planned for 2010, 2011, or 2012.

Chapter 12 – Cash to Debt Service

Cash to Debt Service is the sum of principal and interest payments on outstanding debt. Given all the cash sources and uses described in Chapters 1 through 9, this amount, multiplied by the debt service coverage ratios, determines retail revenue requirements. Cash to Debt Service for 2009 to 2012 is itemized in the middle section of Table 12.1 under the title Cash to Debt Service on Bonds. The total is broken down by the Bonds Sold before 2009 and the Bonds Sold in years 2010, 2011 and 2012. The annual debt service is further divided between interest and principal payments in the bottom two sections of Table 12.1. Data on the years beyond 2010 are presented as integrally related information associated with City Light's plan for a three-year response to the current financial situation.

To help mitigate large increases in rates in the near term, City Light has proposed to delay both the interest and principal payments for one year on all bonds issued in 2010 through 2012. Therefore, for bonds issued in 2010 the first Interest Payment is made in 2011 and the first Principal Payment is made in 2012. Thus, there is no projected impact on 2010 debt service from the 2010 bond issue. The total Debt Service on Bonds Sold in 2010 ($200 million) equals $13.7 million in 2011 and $14.3 million for each of the next 24 years (2012 to 2035). Delaying the first interest payment on the 2010 bond issue until 2011 reduces 2010 revenue requirements by $11.0 million, the amount required to cover that payment 1.6 times, per the proposed financial policies.

The Debt Service Payments on Bonds Sold in 2011 and 2012 follow the same pattern as that of Bonds Sold in 2010.

Table 12.1
Bonds Outstanding at the End of the Years 2009 to 2012

	2009	2010	2011	2012
Cash from the Sale of Bonds	0	200,000,000	200,000,000	111,918,993
Cash to Bond Issue Costs	0	1,643,811	1,802,021	1,217,211
Interest Rate on Bonds Sold		4.83	4.98	5.47
Years over which Principal is Paid		25	25	25
Month Bonds Sold		Feb	Feb	Feb
Delay First Debt Service Payment		Yes	Yes	Yes
Bonds Outstanding at End of Year	1,383,050,000	1,502,315,000	1,622,640,000	1,649,630,156
Bonds Sold before 2009	1,383,050,000	1,302,315,000	1,222,640,000	1,142,305,000
Bonds Sold Feb 1 2010	0	200,000,000	200,000,000	195,406,163
Bonds Sold Feb 1 2011	0	0	200,000,000	200,000,000
Bonds Sold Feb 1 2012	0	0	0	111,918,993
Cash to Debt Service on Bonds	144,805,234	150,693,139	159,366,877	171,008,262
Bonds Sold before 2009	144,805,234	150,693,139	145,674,358	142,647,608
Bonds Sold Feb 1 2010	0	0	13,692,519	14,259,144
Bonds Sold Feb 1 2011	0	0	0	14,101,510
Bonds Sold Feb 1 2012	0	0	0	0
Cash to Interest on Bonds	70,455,234	69,958,139	79,691,877	86,079,426
Bonds Sold before 2009	70,455,234	69,958,139	65,999,358	62,312,608
Bonds Sold Feb 1 2010	0	0	13,692,519	9,665,308
Bonds Sold Feb 1 2011	0	0	0	14,101,510
Bonds Sold Feb 1 2012	0	0	0	0
Cash to Principal on Bonds	74,350,000	80,735,000	79,675,000	84,928,837
Bonds Sold before 2009	74,350,000	80,735,000	79,675,000	80,335,000
Bonds Sold Feb 1 2010	0	0	0	4,593,837
Bonds Sold Feb 1 2011	0	0	0	0
Bonds Sold Feb 1 2012	0	0	0	0

Chapter 13 - Cash from Operations

Cash from operations is the amount of cash inflow from current operating revenues that remains after all cash outflows for current operating expenditures including debt service and all taxes. This residual operating cash is available to fund capital expenditures for CIP, conservation and environmental mitigation. The higher the amount of cash from operations available for capital expenditures is, the lower the amount the utility needs to borrow to fund capital expenditures by issuing long-term debt. Although the utility does not have a specific financial policy target for how much capital expenditure should be funded with cash from operations, funding at least some portion of capital expenditures with operating cash flows is viewed favorably by the utility and the financial community because it reduces reliance on debt. It strengthens the utility's current financial position by lowering its debt burden and reduces the amount that future ratepayers will have to pay so that the utility can generate sufficient cash from operating revenue to cover debt service as required by financial policies.

For the past several years, one of the utility's financial policies has been a requirement that it set rates such that it will be 95% confident of having at least $1 of cash from operations. This means that the utility will not be required to borrow funds to meet current operating expenses. City Light proposes that this financial policy target be removed and replaced with other financial policies during the current rate-setting process, but it is still an important objective of the Department to have sufficient operating cash flow to meet all of its operating expenses and have cash left over in most years to fund some of its capital expenditures. The proposed new financial policies and automatic Power Revenue Adjustment Mechanism (PRAM), briefly described in Section S.2 of the Summary chapter and presented in more detail in Appendices 3 and 4, while not specifically targeting a 95% confidence level, nevertheless are designed to ensure that cash from operations will be $1 or greater with a similar level of confidence.

Chapter 14 - Cash from Contributions

14.1 Introduction

Cash from Contributions is a source of cash that cannot be counted on to pay debt service expenses. This category of cash sources, therefore, does not help reduce revenue requirements for the current rate year. Cash from this source, though, reduces cash requirements from other sources, such as bonds. This category of cash, given planned expenses, affects the amount borrowed and, thereby, affects future debt service requirements and future rates. For that reason, information is presented here on the outlook for this category for the next several years.

Some types of expenditure are funded through specific sources. Capital expenditures and deferred O&M expenditures for conservation, environmental mitigation, and power purchases related to the High Ross agreement are funded from three major sources: 1) contributions, grants and fees from customers and other entities related to the assets or services being acquired as a result of the capitalized expenditure – the main topic of this Chapter; 2) revenue from retail customer rates and other operating revenues; and 3) proceeds from debt.

The amount of revenue from retail customer rates and other operating revenues that is available to provide funding for capital expenditures is the residual amount remaining after all operating expenditures have been met. This amount is determined by financial policy targets that are not directly affected by capital expenditures. The other two funding sources (contributions, grants and fees, and bond proceeds) are directly affected by capital expenditures.

A relatively small amount of capital expenditures is eligible for reimbursement by contributions, fees and grants, determined by the type of project. Proceeds from debt must be sized to make up the difference between the amount of planned capital expenditures and the amount of funds available from operating revenues, contributions, grants and fees. The more City Light can leverage its capital costs with funding from contributions, grants and fees, the fewer funds are required from long-term borrowing. Table 14.1 displays the 2009-2012 forecast of funding from contributions, grants and fees, breaking it into the major categories, which will be further described below.

Table 14.1
Capital Contributions, Grants and Fees
(Millions of Dollars)

	2009	2010	2011	2012
Contributions in Aid of Construction	$21.1	$26.6	$25.4	$33.4
Grants from Sound Transit	3.5	0.7	0.5	0.3
FEMA Grants	0.3	0.0	0.0	0.0
Other Capital Fees and Grants	0.0	0.1	0.1	0.1
BPA Funding for Conservation	0.1	2.3	4.7	0.0
Total	25.0	29.7	30.7	33.8

14.2 Contributions in Aid of Construction (CIAC)

Customers that install new electrical service or upgrade their existing service pay installation charges that reimburse City Light for part of the cost of equipment and hookup to the City Light system. Customers also pay the capital cost of non-standard service that they request. Examples of the latter are underground service and a second feeder. When large customers have buildings or other facilities under construction that require City Light to relocate or replace the utility's feeders or other equipment, customers must also reimburse the utility for these costs. City Light projects CIAC to increase from $21.1 million in 2009 to $26.6 in 2010. This is also a $7.5 million increase from the average CIAC projected for 2007-2008 during the last rate-setting process. Major categories of CIAC-reimbursed capital expenditures in 2010-2012 are itemized in Table 14.2.

Table 14.2

Contributions in Aid of Construction
(Millions of Dollars)

	2009	2010	2011	2012
Transmission	$0.6	$1.4	$1.4	$0.8
Cedar Falls Switchyard Expansion and Line Extension	3.6	3.6	-	-
Distribution Capacity Additions	2.1	2.1	1.3	1.6
Network Additions and Services	2.8	3.8	2.1	2.2
Overhead and Underground Services	5.7	6.8	8.9	19.6
Transportation Driven Relocations	3.2	2.5	2.3	4.4
Streetlights	2.3	3.2	3.2	3.2
Creston-Nelson to Intergate East Feeder Installation	0.6	3.1	4.1	-
First Hill Connector Streetcar Engineering	-	0.1	2.1	0.1
Other	0.2	0.1	0.0	1.6
Total	21.1	26.6	25.4	33.4

14.3 Fees for Services and Grants

When construction projects of local governments or other agencies require City Light to relocate, construct, or replace utility equipment, the local government or agency may be required to reimburse the utility for its costs. Examples include street widening, bridge rehabilitation or tunnel digging. The largest of these construction projects are tracked as Special Projects, which currently include Sound Transit Light Rail and the Alaskan Way Viaduct. Seattle City Light is receiving funding from Sound Transit. The utility does not expect to be reimbursed for the cost of relocating electrical equipment before and after construction of the Alaskan Way Viaduct, however; therefore, no grant funding for this project is included in the forecast.

The Sound Transit Light Rail project has required a substantial amount of work on the City Light distribution system to support construction of the project and electric service to the light rail system. Since the project's inception, in 2002, City Light has received $25.4 million in grant funding for this work. As Table 14.1 shows, City Light is expecting to receive another $3.5 million in 2009. These grants will decline through 2012, as the project nears completion.

City Light also receives grant funding from the Federal Emergency Management Agency (FEMA) to reimburse it for unanticipated expenditures to repair equipment and restore power to customers after outages caused by storms, floods, earthquakes and other disasters. This funding is too uncertain to forecast beyond 2009 because it is the result of unanticipated events, is highly variable in amount from year to year, and can take a year or longer to collect, due to the lengthy processing period required by FEMA.

Every year, City Light receives a variety of other Federal, State and local government grants for capital expenditures related to endangered species, homeland security, transportation improvements, and other government-supported projects. These grants can also vary significantly from year to year in ways that make them difficult to forecast; therefore, the forecast is currently limited just to those related to endangered species, projected to be $0.1 million annually in 2010-2012.

14.4 Sources of Funding for Conservation

The primary source of funding for City Light conservation programs is federal funding provided by the Bonneville Power Administration (BPA), which takes two forms. The first type is a "Conservation Rate Credit" included in cash from operations and described in Chapter 3. The second type of BPA funding is the capital contribution displayed in Table 14.1. The $0.1 million received in 2009 is in accordance with a "Conservation Augmentation Agreement" that funds conservation projects started during BPA fiscal years 2002-2006 (October 1, 2001-September 30 2006)[9] . A small number of these projects is still being completed in 2009. Conservation projects started during BPA fiscal years 2007-2011 are being funded pursuant to a "Conservation Acquisition Agreement" that replaced the "Conservation Augmentation Agreement". Because of terms that were modified under the new agreement, City Light opted not to accept new BPA grant funding during BPA fiscal years 2007-2009. City Light has found it economically advantageous to resume this funding in BPA fiscal years 2010 and 2011 and anticipates receiving $2.3 million in calendar year 2010 and $4.7 million in calendar year 2011. There is no agreement currently in place for this funding beyond September 2011; therefore, the forecast assumes zero from 2012 onward.

[9] A BPA Fiscal Year for the year listed is the twelve month period beginning October 1 of the prior calendar year.

Chapter 15 - Cash from Bond Proceeds

Cash from Bond Proceeds is not available to pay debt service costs and, therefore, does not affect revenue requirements for the current rate year. The amounts borrowed, of course, affect future debt service requirements and future rates. Cash from Bond Proceeds for 2009 to 2012 is shown in the middle section of Table 15.1 as the Cash from the Bond Proceeds Account. This measure is equal to Cash to Capital Expenditures minus Cash from Operations and Contributions. It is the residual amount of Cash required to pay for Capital Expenditures. Capital Expenditures referenced here are the Total Expenditures for Capital, Conservation, and Deferred O&M.

Cash from Bond Proceeds is not the amount of Cash from the Sale of Bonds. This measure is shown in the top section of Table 15.1. Bonds are sold in advance of the time the cash is needed for capital expenditures. The Cash from the Sale of Bonds minus the Cash to Bond Issue Costs is the Cash to the Bond Proceeds Account.

Table 15.1
Cash to and From Bond Proceeds Account

	2009	2010	2011	2012
Cash to the Bond Proceeds Account	0	198,356,189	198,197,979	110,701,782
equals				
Plus Cash from the Sale of Bonds	0	200,000,000	200,000,000	111,918,993
Minus Cash to Bond Issue Costs	0	1,643,811	1,802,021	1,217,211
Cash from the Bond Proceeds Account	196,167,741	176,331,182	148,674,511	160,306,689
equals				
Plus Cash to Capital Expenditures	216,369,570	260,077,435	241,962,319	277,709,765
Minus Cash from Operations	-4,817,194	54,018,178	62,537,823	83,581,066
Minus Cash from Contributions	25,019,023	29,728,075	30,749,985	33,822,010
Cash to (from) the Bond Proceeds Account	(196,167,741)	22,025,007	49,523,468	(49,604,907)
Balance in Bond Proceeds Account				
at Beginning of Year	224,224,173	28,056,432	50,081,439	99,604,907
at End of Year	28,056,432	50,081,439	99,604,907	50,000,000

The last section shows the Cash to (from) the Bond Proceeds Account. This measure is the Cash to the Bond Proceeds Account minus the Cash from the Bond Proceeds Account. The Balance in the Bond Proceeds Account at the beginning and end of the year is shown at the bottom of this section of the table. The 2010 and 2011 bond issues were rounded to $200 million.

Chapter 16 – Cash to Capital, Conservation and Deferred O&M

16.1 Introduction

The Department maintains long-range capital improvement and conservation acquisition programs to ensure the availability of adequate supplies of power, to provide a high level of service reliability to its various customer groups, to meet City and State requirements for transportation projects, and regulatory compliance for environmental and mitigation requirements. City Light's Proposed 2008 Strategic Plan has further examined our business needs and identified specific strategic priorities. These strategic priorities shape our capital requirements, which are proposed in City Light's current capital budget and revenue requirement. Key priorities include: environmental stewardship, improved energy delivery infrastructure, balanced resource portfolio, financial strength and high performance organization. The capital forecast has identified investments that are needed to fund these initiatives. The following initiatives support the Utility's strategic effort:

- To improve City Light's energy delivery infrastructure, City Light is proposing investment in asset management and business process re-engineering, Smart-Grid communications within the utility and with customers, security and emergency preparedness as well as in core utility infrastructure, which enables City Light to provide a high level of customer service.
- To achieve a balanced resource portfolio and environmental stewardship goals, City Light gives priority to relicensing the Boundary Dam, mitigating environmental impacts of its operations and achieving conservation goals presented in the Conservation Implementation Plan.
- To maintain and improve our financial strength and organizational performance goals, City Light plans to invest in enterprise risk management and corporate performance efforts and provide information technology support to achieve workplace efficiency and improved communications in all areas of its business.

In addition to its strategic priorities, City Light is required to relocate its electrical equipment for local and State transportation projects, to underground services for its suburban city franchises and to make overhead and underground capacity additions upon customer request. Agencies and customers make contributions towards the cost of these services. The largest upcoming project is the Alaskan Way Viaduct and Seawall Replacement.

The Department's Conservation Program provides funding for investments in the residential, commercial and industrial sectors of the service territory to achieve the Department's long-term energy savings goals. City Light began deferring conservation costs in 1984 per Council Resolution 27372. Since 1986 they have been amortized over twenty years. Amortized costs include only program-specific expenditures that are related to installation of long-lived conservation measures. Administrative costs associated with managing and evaluating programs are part of the O&M forecast and are expensed in the year they occur.

In addition to CIP expenditures and conservation programs, capital requirements include other deferred costs. Other deferred costs result from the fact that some of the Utility's expenditures do not produce conservation or capital assets for City Light but still relate to activities that have impacts extending beyond the year these payments are made such as the High Ross Agreement. These payments are not expensed in the year they are made but are amortized over several years. They are grouped with CIP and conservation because they have the same impact on revenue requirements as capital expenditures.

Capital expenditures, deferred conservation and other deferred costs do not affect current period revenue requirements but have a significant effect on the revenue required from customers over time. They affect borrowing requirements and are a major factor in determining the debt issued each year. Debt service payments affect the revenue required from customers in the following years because coverage of first and second-lien debt service is a component of revenue required.

The City's biennial budget process approves the annual funding levels for both the CIP and the conservation resource acquisition plan. Expenditures for all new and existing projects are reviewed and project details for each capital project are kept in City Light's ESPro budget system. Capital projects become part of the City Light CIP proposal after an identification, selection and prioritization process in which project justification, costs and benefits are closely examined. City Light has implemented a more rigorous utility-wide prioritization process over the last several years, requiring that new initiatives and existing projects with major changes in scope or budget provide a business case and economic analysis that justifies funding for the project. The economic analysis includes a discussion of all benefits and costs, including customer service, legal and technical considerations, environmental and risk impacts. Every two years, the Mayor and the City Council, as part of the City's biennial budget process, review proposed capital expenditures for the budget period, approving expenditures for the first year and endorsing expenditures for the second year.

Sections 16.2 and 16.3 present information on capital expenditures and the CIP forecast. Deferred conservation expenditures are reviewed in Section 16.4 and other deferred costs in Sections 16.5 and 16.6. Section 16.7 discusses the three sources of funding for these expenditures**.**

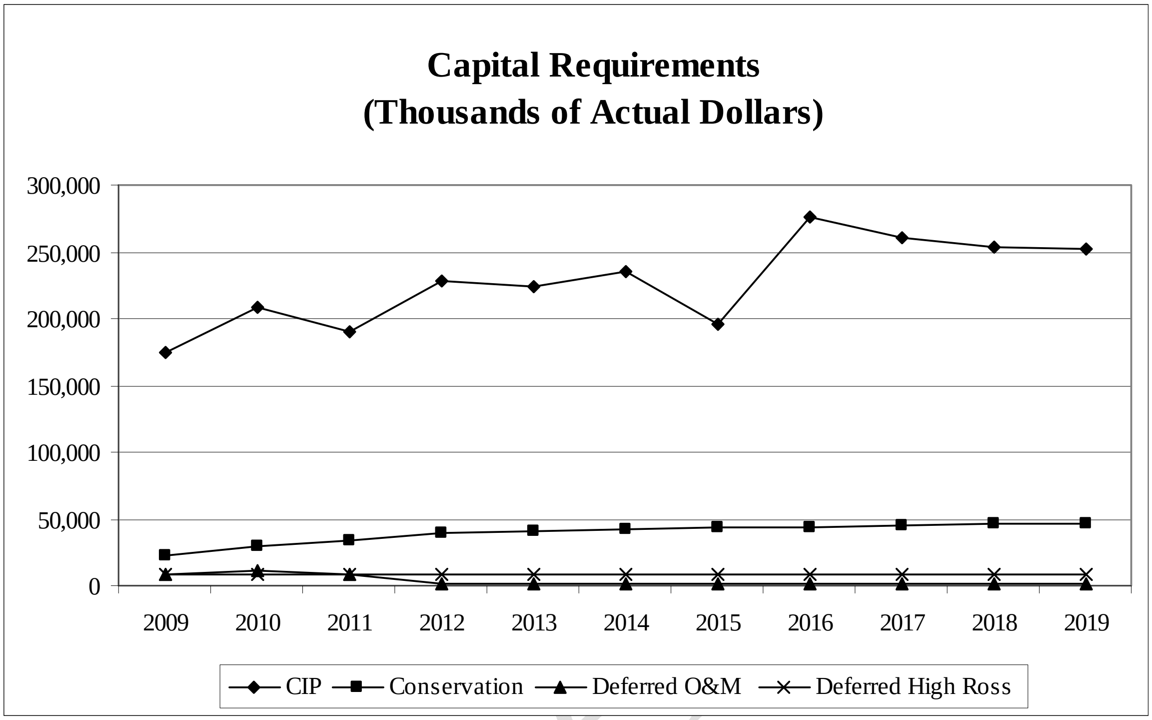
16.2 Forecast of Capital Requirements

Figure 16.1 shows each major component of the capital requirements forecast for years 2009-2019. City Light's Capital Requirements, which include capital improvement projects (CIP), conservation and other deferred expenditures, are projected to increase from $216.4 million in 2009 to $309.5 million in 2019 or by $93.1 million over the ten-year planning horizon. Capital improvement project expenditures are projected to account for $77.2 million of this increase, primarily in distribution plant.

Conservation is projected to grow at the rate of inflation, while deferred High Ross charges are projected to remain fixed at $9.1 million. Deferred O&M is expected to be in the $9-$12 million range in 2009-2011 but decrease to around $1-$2 million annually from 2012 onward because

Boundary relicensing deferred O&M expenditures end in 2011. Components of the capital requirements forecast are discussed in sections below.

Figure 16.1



16.3 Major Projects in the Capital Improvement Expenditure Forecast

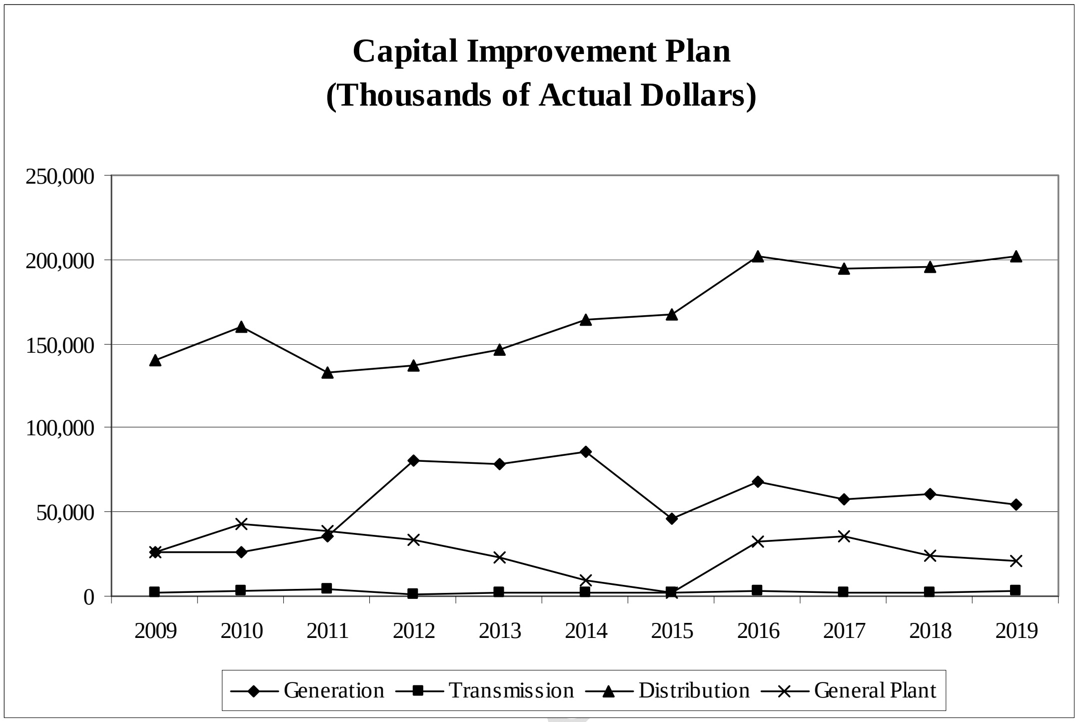
The Revenue Requirements Analysis (*RRA*) forecast includes all projects individually documented in the Department's Budget Proposal. The six year capital plan expenditures include loadings for benefits, transportation, and administration and general cost allocation, based on the number of labor hours estimated for the project. The RRA forecast assumes a 10% under-expenditure in CIP.

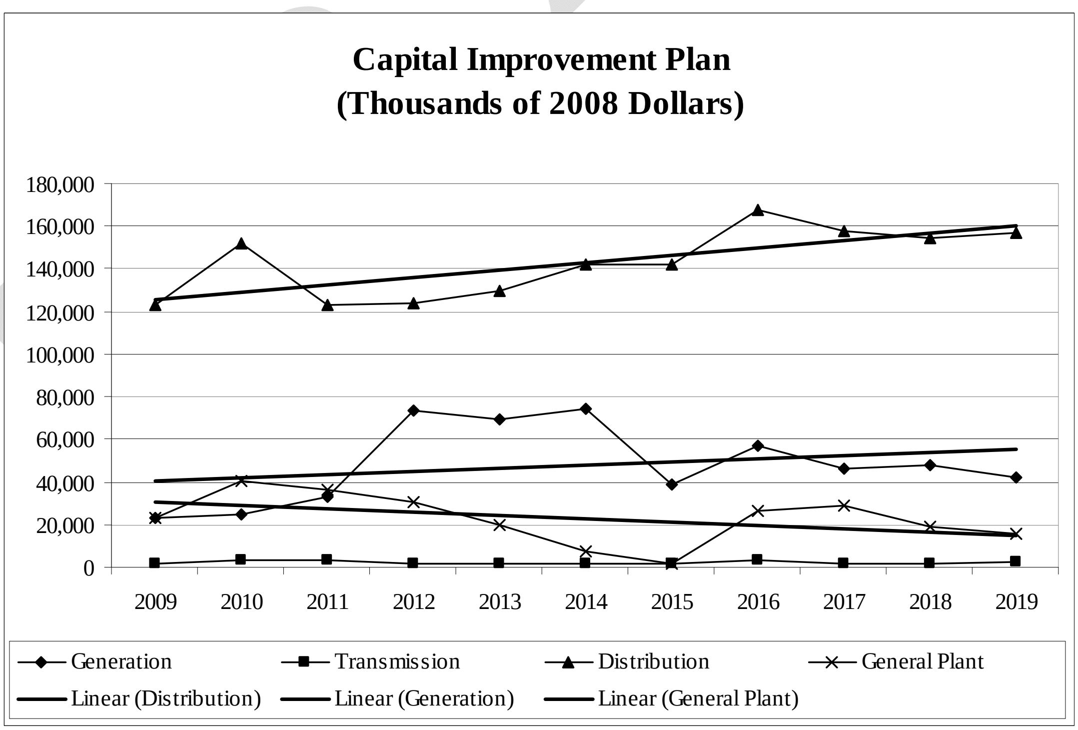
The current forecast also reflects additional funding requirements for specific projects approved in budget deliberations (Budget Issue Papers). Specifically, funds were added beginning in 2010 to enable several new technologies, which will make neighborhood underground cable and street light replacements more efficient and environmentally safe ($4.6 M). Additional funds were also requested to meet franchise customer requests for undergrounding ($4.1 M), to finish implementation of City Light's Outage Management System ($1.8 M) and to enhance the reliability of fiber communications between King County and the Skagit facilities ($0.3 M).

Beyond the detailed six year plan, the financial forecast makes provision for the expected level of spending on CIP projects required to maintain utility core functions, including customer service needs, to address City Light's strategic initiatives discussed in its proposed 2008 Strategic Plan and to meet City and Other Agency requirements.

The *RRA* forecast classifies CIP expenditures according to functional categories: generation, transmission, distribution and general plant. Figure 16.2 shows actual values and the trends for each of these categories in inflation adjusted or constant 2008 dollars. Distribution is the largest category of expenditures. Expenditures are expected to grow at a rate of $3.4 million per year

Figure 16.2





higher than the rate of inflation. The largest single driver in expenditures is the Alaskan Way Viaduct.

Generation expenditures are projected to increase at a rate of about $1.5 million (constant $2008) annually. Expenditures peak in 2012 to 2014 when City Light plans to rebuild the Boundary Units 55 and 56 generators and replace the turbine runners and when the Boundary project mitigation work begins. Mitigation costs continue through 2019 and beyond. General Plant expenditures are trending downward at $1.5 million (constant $2008) annually as specific, larger information technology, communications, and facilities projects are coming to an end by 2015. Post 2015, expenditures are projected to return to expenditure levels somewhat lower but more consistent with longer term average expenditures levels as information, communication, financial and accounting systems, buildings, workplace furnishings and equipment age and require replacement. Transmission costs are planned to remain flat over the planning period.

Table 16.1 on the next page presents forecast information for selected CIP projects by major capital category for years 2009 to 2015. Each major expenditure category is discussed in more detail below for both the near-term **(Six-Year Plan)** and the longer term outlook (2016 to 2019). Years beyond 2015 have fewer specific projects identified during that period. Trend forecasts for core categories are used to create a forecast for outlying years. Individual projects that are expected during that timeframe are noted in the discussion below.

16.3.1 Generation Plant ($317.3 Million)

Generation Plant includes facilities used to produce electricity. Typical assets would be reservoirs, dams, waterways, waterwheels, turbines, generators and accessory electrical equipment. Generation expenditures are projected to total $317.3 million during the six-year planning period, averaging about $52.9 million per year and representing about 25% of planned expenditures for that period. About 66% of generation expenditures will be dedicated to core utility functions that will maintain generation infrastructure and insure reliability of power availability to customers. The remaining funds will provide for environmental mitigation related to relicensing the Boundary Plant ($93.9 million), which is expected to continue throughout the 10-year outlook, and endangered species mitigation ($5.9 million).

Environmental Mitigation ($100.7 Million). Boundary Dam is Seattle City Light's largest generating station, producing approximately 25% to 40% of its power supply. The City must obtain a new federal license to continue to operate the Boundary Dam project. This project will fund mitigation measures required by the new Federal Energy Regulatory Commission (FERC) license expected to be issued in September 2011. Protection, mitigation and enhancement (PME) measures are currently being developed by City Light as part of the license application filed with the Federal Energy Regulatory Agency in September 2009. Expenditures total $100.7 million in the six-year capital plan beginning in 2010 and represent about 32% of generation expenditures for that period. Mitigation expenditures are expected to continue throughout the 10-year outlook.

Table 16.1
Selected CIP Projects
(Thousands of Actual Dollars)

Actual Dollars	2009	2010	2011	2012	2013	2014	2015	6-Year Plan
Generation								
Environmental Mitigation	906	1,655	1,444	10,730	25,443	32,692	28,780	100,743
Skagit Plant Improvements	11,465	11,744	10,927	16,789	26,914	24,670	3,343	94,387
Generators / Turbine Runner	2,588	3,297	7,772	33,027	12,033	16,086	7,335	79,550
Boundary Plant Improvments	4,470	2,661	7,895	8,367	4,603	2,109	1,581	27,216
Other Generation	4,030	4,067	4,152	3,992	1,273	1,966		15,449
Subtotal	23,458	23,423	32,191	72,905	70,265	77,522	41,040	317,346
Transmission								
Other Transmission	1,545	3,150	3,382	1,406	1,440	1,475	1,511	12,364
Subtotal	1,545	3,150	3,382	1,406	1,440	1,475	1,511	12,364
Distribution								
Capacity Additions	27,014	29,761	19,408	19,273	19,725	20,248	30,009	138,424
Alaskan Way Viaduct	3,760	5,594	6,512	12,580	21,889	36,395	38,728	121,698
Service Connections	18,107	16,355	17,182	17,680	18,102	18,563	15,374	103,257
Other Substation	13,338	13,883	13,543	17,233	16,147	15,239	15,260	91,304
Underground Projects	6,722	9,757	18,168	14,748	10,845	6,210	6,297	66,025
Other Distribution	11,662	14,205	9,594	8,962	9,046	7,516	8,348	57,672
Street and Floodlights	4,298	7,216	9,569	9,562	9,792	10,047	10,274	56,459
Network Additions / Services	11,369	13,682	7,559	7,742	7,927	8,127	8,310	53,347
Pole Replacements	3,784	6,481	6,316	6,468	6,623	6,790		32,678
26 kV Conversion	1,709	3,977	2,876	2,838	3,247	5,072	5,171	23,179
Smart Grid	1	1	523	1,939	5,687	7,068	7,232	22,451
Suburban Undergrounding	5,347	10,182	6,491	2,404				19,077
Overhead Equipment	2,739	4,604	1,150	1,036	1,061	4,929	5,040	17,821
North Downtown Substation	13,025	7,586						7,586
Mobile Workforce				497	1,128	1,157	581	3,362
Regional Transit	3,492	642	452	265	402	622	410	2,794
Subtotal	126,367	143,925	119,344	123,226	131,622	147,983	151,035	817,135
General Plant								
Vehicle Replacement	1,047	5,127	7,386	8,459	8,663	5,309		34,945
Asset Management	8,643	9,771	7,228	7,606	444			25,048
Other General Plant	7,017	5,322	7,647	4,386	5,070	189		22,615
Communications	1,828	2,803	5,825	6,171	2,795	2,507	1,953	22,053
Information Technology	2,895	8,994	4,673	3,226	2,907			19,800
Security	550	2,457	1,177	613	628			4,874
Outage Management System	1,687	3,979	851					4,830
Subtotal	23,667	38,452	34,787	30,462	20,507	8,005	1,953	134,165
Grand Total	175,037	208,949	189,704	227,999	223,834	234,986	195,538	1,281,009

Skagit Plant Improvements ($94.4 Million). The Skagit Hydroelectric Project generation plants include Ross, Gorge, Diablo and Newhalem powerhouse, dams and related facilities. The largest single project, Gorge Second Tunnel installation ($57.5M), is discussed below. In addition, City Light will make investments at the Skagit powerhouses, facilities and grounds at Diablo ($12.7 M), Ross ($7.2 M), Gorge ($5.0M), Newhalem ($1.7M) and related Skagit facilities ($9.8M). Investments include replacement of transformers, breakers, switch gear and other equipment. They also provide for oil containment improvements to avoid environmental damage, installation of standard rock fall mitigation measures, including drapes, rock bolts, and rock fencing to protect workers and plant assets, and improvement of network controls.

Gorge Plant – Second Tunnel Installation ($57.5 Million). This project will bore a second tunnel parallel to the existing two-mile long tunnel. The main purpose of the second tunnel is to increase the efficiency of the Gorge plant by reducing energy lost in the power tunnel on the way to the turbine/generator units. The resulting lower water velocity in the two tunnels together would increase overall plant efficiency without any change in water flow or plant operations. This efficiency improvement would increase annual generation by about 50,000 MWh.

Generator and Turbine Runner Rebuilds/Replacements ($79.6 Million).

Replace Turbine Runners at Boundary Units 55 and 56 ($21.4 million). The existing turbine runners were manufactured by Toshiba Corp. and went on line in 1986 and 1987. Performance testing determined that both units are performing significantly under what is expected from a newly designed hydro turbine. City Light expects that overhauling Units 55 and 56 with new, high efficiency turbine runners will generate more energy for the same water resource. City Light expects a 2% efficiency increase (minimum) for both Units 55 and 56 turbine runners, which will produce an annual energy increase of 39,840 MWh per year, on average. Also, this "new energy" will help City Light meet the renewable energy requirements of I-937 because it is an efficiency improvement on an existing generation unit. A new, high efficiency turbine runner will provide clean, inexpensive renewable energy for 30+ years to come.

Rebuild Powerhouse Generators ($58.2 Million). The purpose of rebuilding generators is to increase the reliability of the generator, when the age and condition of the asset warrant it. City Light plans to rebuild five units at the Boundary Plant and three units at the Skagit plant over the six-year period 2010 to 2015.

Boundary Plant Improvements ($27.2 Million). In addition to generator/turbine rebuilds and replacements and relicensing mitigation efforts discussed above, City Light must replace and/or upgrade other electrical and plant equipment and infrastructure. Over the six-year horizon, City Light expects to do work on switchyard transformers ($6.4 million), perform rock damage mitigation ($6.2 million), improve radio communications ($2.7 million) and install a trash rack to enhance power generation ($1.5 million).

Other Generation ($15.4 Million). City Light plans to make investments in its Cedar Falls and South Fork Tolt plants and facilities. The largest project will make repairs to the penstock at the Cedar Falls Powerhouse ($5.8 million), which will insure continued operation of the power plant and reduce risks to Seattle's water supply and fish spawning on the Cedar River. City Light will also make improvements that are necessary to comply with NERC and WECC regional reliability standards ($2.1 million). Improvements include power system stabilizers, generator and control system testing equipment, cyber security equipment, and system disturbance monitoring equipment.

16.3.2 Transmission Plant ($12.4 Million)

Transmission plant includes poles, towers and conductors used to carry electricity from generation facilities to substations. Transmission expenditures are projected to total $12.4 million during the six-year planning period, averaging about $2.0 million per year and representing about 1% of planned expenditures for that period. The transmission reliability project ($9.2 million) supports engineering, construction, and other work necessary to improve or maintain the reliability of the overhead or underground transmission system. Reliability projects include line rebuilds, new lines to enhance reliability of a substation, new line configurations to improve operation, and relocations required to maintain the transmission system. Investments are also needed to relocate transmission facilities at the request of other agencies ($2.7 million). Relocations are necessitated by road realignments, construction of facilities, regional upgrades, and changes in lighting.

16.3.3 Distribution Plant ($817.1 Million)

Distribution includes substations and other distribution plant equipment as well as utility equipment relocation costs associated with transportation projects. The Department plans to spend about $817.1 million from 2010 to 2015 on improvements and additions to the distribution system, averaging $136.2 million per year and representing about 64% of total CIP expenditures.

Capacity Additions ($138.4 Million). The expenditures projected in this group of projects are for building or reconductoring line segments, replacing poles, adding cables for increased customer loads, installing new feeders, and adding underground facilities to match changing service demands in the City Light service territory.

> **Broad, Union and Massachusetts Street Substations and First Hill Network Capacity Additions ($47.3 Million).** These projects provide a programmatic approach for comprehensive management of underground network assets (electrical and in some cases civil) serving customers in network areas. These projects provide sufficient and reliable electrical capacity for the growing and changing power needs of City Light customers.
>
> **Overhead and Underground Customer-Driven Capacity Additions ($33.9 Million**). City Light adds capacity to the distribution system to accommodate increased load from specific new customer projects. City Light is reimbursed by the customers for this work.
>
> **Underground System Capacity Additions ($25.6 Million**). This project provides electrical lines from substations to customers' property lines so that City Light has sufficient capacity to serve its customers and maintain reliability. This project builds new and replaces old underground lines and may replace rotten and damaged poles in the distribution system with underground facilities beneath them. City Light customers pay for a portion of this work.
>
> **Cruise Ship Service Connections**, starting in 2015 **($8.4 Million).** This project installs electrical service connections to the docks which support cruise ships moored in Elliott

Bay. The project allows the ships to power their systems while protecting the atmosphere. Expenditures on this project are expected to continue through 2019.

Alaskan Way Viaduct ($121.7 Million). The Alaskan Way Viaduct is part of State Route 99, serving north/south traffic through downtown Seattle. Viaduct support structures were damaged during the 2001 Nisqually Earthquake. The Washington State Department of Transportation conducted a plan and study for demolition and replacement of the viaduct. City Light has critical transmission and distribution infrastructure along the project corridor, all of which must be relocated once or twice during the project. This project includes **Mercer Corridor West Phase Relocations** ($12.1M). Expenditures on this project are expected to continue through 2019.

Service Connections ($103.3 Million). There is a continuous need for new and enlarged overhead and underground service connections within the City Light service territory, outside of the network areas. Customer service connection requests fluctuate with land use development and changing demand. Most of this work is billable to the customer. Voluntary underground projects are also included in this set of capital projects.

Other Substation ($91.3 Million). Substation additions and improvements are a critical component of the energy delivery system. City Light expects to make capacity additions ($7.9 million) as well as replace transformers ($15.7 million) and breakers ($21.5 million) over the next six years. Plans are also underway to make improvements to relays ($16.2 million) and substation equipment ($17.6 million).

Underground Projects ($66.0 Million). This group of projects rebuilds or replaces underground systems in Seattle neighborhoods. An underground rebuild is scheduled in Laurelhurst ($4.4 million). The neighborhood voluntary undergrounding project is included ($2.6 million).

Mercer Corridor Relocations ($28.3 Million). This project converts the existing overhead power distribution systems to underground within the boundaries of a larger SDOT-managed project to widen Mercer Street to three lanes each way and reconstruct Valley Street between Dexter Avenue North and I-5. The project also relocates existing transmission lines underground. Seattle City Light is responsible for the electrical design and construction of system relocations and underground conversion of the electrical power distribution system. SDOT is responsible for the civil engineering design and construction to provide for Seattle City Light's underground system. Funding from property owners adjacent to the existing overhead transmission line and non-City funding accommodates the conversion of the existing Broad-University overhead transmission line to underground.

Citywide Underground Initiative ($14.3 Million). This project provides funding for emergent undergrounding projects. It provides a baseline commitment to take advantage of undergrounding opportunities in the course of transportation and utility projects in the City. Private developers may participate in the cost of undergrounding adjacent to parcels being developed.

Other Distribution ($57.7 Million). This project provides funds for a variety of distribution activities, the largest of which are discussed below.

> **Network Rebuilds ($25.6 Million).** This project repairs or replaces damaged electrical manholes, vaults and ducts located in the street right of way within the Downtown Central and Pioneer Square business districts. The Network has 1,470 manholes/vaults, of which 78 need to be completely rebuilt and 350 need roof rebuilds.

> **Transportation Driven Relocations ($9.6 Million).** This project moves electrical lines to accommodate or take advantage of transportation-related projects being constructed by other agencies. The project builds new and replaces old line segments, installs and replaces poles, and adds or renovates underground facilities to the distribution system, as necessary, to relocate distribution systems for transportation projects, street vacations, or other projects proposed by outside (non-City Light) agencies. Some projects are paid for by City Light and some are paid for by the requesting agencies.

> **Neighborhood Underground Cable Injection ($4.9 Million).** This projects uses cable injection in Seattle neighborhoods to extend the useful life of direct buried cables without replacing them.

> **State Route 520 Bridge Replacement.** This project relocates electrical infrastructure to support replacement of the State Route 520 Bridge. Expenditures on this project are expected to start after 2015 and continue through 2019. Expenditure levels are projected to be about $12 million per year.

Streetlights and Floodlights ($56.5 Million). Lighting projects in the 2010 to 2015 capital plan include provision for additional customer-requested streetlights, including requests from unincorporated areas served by City Light. Lighting projects address public safety concerns in certain commercial and residential neighborhoods and major maintenance for arterial streetlights in Seattle whose ownership was transferred from the City to City Light at the end of 1999.

> **Transportation Street Lights ($8.2 Million).** This project relocates Seattle City Light-owned streetlights as required by transportation projects.

> **LED Street Light Conversion ($31.4 Million).** This project replaces 41,000 residential streetlight fixtures with LED streetlight fixtures north of Denny Way and northeast of 65th Street. The plan includes monitoring upgrades in LED streetlight technology. This project will reduce energy consumption by 40% for those lights replaced, provide Greenhouse Gas Avoidance of 5,446 metric tons of carbon per year and reduce the maintenance cost of the Utility's streetlight system. The savings in energy and maintenance costs will pay for the initial investment within the life of the new system.

Network Additions and Services ($53.3 Million). These projects provide for the improvement and expansion of the networks that serve high-density load areas (downtown, University District, First Hill), ensuring system reliability and continuity of service. The planned work includes installation, upgrading and replacement of conduits, maintenance holes, vaults, feeders, primary cables, transformers, network protectors, fire protection systems, and switch gear, as well as improvements to the network transformer monitoring system.

Pole Replacements ($32.7 Million). This project pays for a contractor to inspect and survey Seattle City Light's entire pole system. The contractor classifies the poles into three categories depending on how best to prolong the useable life of each pole. The contractor treats a Category One pole with approved chemicals, in situ, at the time of the inspection. The contractor refers a Category Two pole to City Light to be reinforced with one or two steel sleeves at the ground line. The contractor refers a Category Three pole to City Light to be replaced with a new pole. The project also provides for dedicated City Light crews, equipment and material to perform the reinforcement or replacement, at a rate of approximately 900 reinforcements and 1,100 pole replacements per year. The contractor also provides an accounting of the usage of pole rental space by other parties. The data is the basis for collecting rental fees from the owners of the attachments.

26-kV Conversion ($23.2 Million). Conversion of both the overhead and underground distribution systems from 4 kV to 26 kV is a long-term project for the Utility. The conversion provides greater capacity and reliability and allows the system to meet increased capacity demand.

Smart Grid ($22.5 Million). City Light intends to build two-way energy and information communication technologies between the Utility and its customers that will provide operational and energy use information so that customers may use energy efficiently and the utility can manage its systems in a cost–effective and efficient way. Smart Grid investments reflected in the CIP currently comprise two projects: Substation and Distribution Automation Systems. This level of effort does not reflect City Light's recent Smart Grid grant proposal to the US Department of Energy, which identifies needed investments for Advanced Metering Infrastructure as well as Substation and Distribution Automation, totaling $204 million over years 2010 to 2012, funded in part by a DOE grant ($104 million). City Light will revise the CIP once it receives the DOE grant award notice expected in November or December 2009.

> **The Substation Automation System ($13.6 Million).** This project builds a smart system infrastructure in the substations that communicates intelligently with line-switching equipment. It also provides communication between substation equipment and line switches for coordinated switching.
>
> **The Distribution Automation System ($8.8 Million).** This project installs strategically placed power line switches, which are able to perform automatic outage restoration, shift blocks of load to maximize the efficiency of power lines and reconfigure power lines into their optimal configuration. This project also provides remote control of operations of switches on power lines, real-time data, which allows for advanced monitoring of conditions in distribution power lines, and standardized line switching equipment in City Light's service area.

Undergrounding for Suburban Customers in Shoreline, Burien and SeaTac ($19.1 Million). City Light has franchise agreements with these suburban cities that allow them to request undergrounding services. The cost of these projects is recovered over time, through City Light rates charged in those jurisdictions during the 25 years following project completion.

Overhead Equipment Replacements ($17.8 Million). This project supports the capitalized portion of work resulting from unplanned, non-emergency, overhead outages to ensure that customers' electric power is restored as quickly as possible. These outages result from events such as storms, accidents, and equipment failures. Replacement includes permanent storm repairs and construction of new infrastructure to bypass failing equipment. Pole and transformer replacements that are required to restore power are among the elements capitalized during such repairs. The project budget includes travel, meals, and other costs for visits to generation facilities to make needed repairs.

North Downtown Substation ($7.6 Million). The purpose of this project is to provide reliable service and efficiently meet anticipated load growth in the North Downtown neighborhood by building a 200 MVA substation in the area. This project would design and build a 200 MVA substation in the North Downtown area to meet load growth and support development of an underground network. Currently projected costs include site acquisition only.

Mobile Workforce ($3.4 Million). Starting in 2012, this project provides mobile communication and computing equipment for Seattle City Light workers to use in the field. This project supports City Light's efforts to implement work management, smart grid and performance management.

Regional Transit ($2.8 Million). City Light requires funds to relocate its transmission and distribution systems so that Sound Transit can construct the Central LINK and North LINK light rail projects. In addition, City Light must supply power to the light rail system. The original project, which covers the 14-mile segment from the Convention Place Station to South 154th Street, near Seattle/Tacoma International Airport, is complete. City Light's next step is to supply power to the light rail system between the Convention Place Station and the University of Washington Station. City Light is now working with Sound Transit to plan the North LINK light rail segment, which runs north of the University of Washington Station, through the Roosevelt area to Northgate.

16.3.4 General Plant ($134.2 Million)

General plant includes assets not included in the other four categories: buildings, such as the North and South Service Centers, computer equipment and information systems, office furniture and communications and mobile equipment. Programmed expenditures of $134.2 million will provide for general plant improvements and/or replacement over the 2010-2015 period, averaging about $22.4 million per year and representing about 10% of total capital expenditures over the six-year period. Major components are discussed below.

Vehicle Replacement ($34.9 Million). The Vehicle Replacement Project will replace and expand City Light's heavy-duty mobile equipment fleet, as well as gradually replace light-duty vehicles previously leased from the City's Fleets and Facilities Department. The Utility deferred replacement of vehicles during the energy crisis, which created a significant backlog of vehicles that have exceeded their useful life cycle.

Asset Management ($25.0 Million). Asset management funds will be used to support design, development, implementation and installation of hardware, software and related tools to track asset information and work history, which will enable the Utility to make better asset investment decisions. City Light proposes to use Oracle Work Asset Management (WAM) and Utility Group Business Intelligence (BI) products, and establish standard business processes.

Other General Plant ($22.6 Million). This project includes expenditures for non-electrical facilities at North and South Service centers ($2.5 million), including the South Service Center Spokane Exit Modification ($5.2 million), which is required due to the new Spokane Street exit. It also makes provision for workplace and process improvement ($6.3 million), special work equipment ($3.3 million) and other environmental and safety modifications.

Communications Improvements. ($22.1M). The major communications projects included in the 2010-2015 CIP will improve fiber optic cable and radio communications infrastructure that supports distribution, transmission and generation control systems.

> **Distribution Area Communications Networks ($9.4 Million).** This project installs fiber cable and equipment to all City Light dams, substations and service centers to create a secure, reliable, fast and redundant digital communications system for operations command and control. The fiber infrastructure provides a secure path for power distribution system control and dispatch, energy management system data, and other City Light communications. This project also supports Smart Grid projects, including Substation Automation, Distribution Automation, Distributed Generation, and advanced metering infrastructure projects, which is a strategic priority for the Utility.

> **Transmission and Generation Radio Systems ($5.0 Million).** This project builds or replaces communications infrastructure consisting of fiber optic rings, digital microwave, telephone networks and two-way radio systems. This project provides City Light with command and control capabilities for the operation of the electrical system to ensure the safe, reliable and efficient operation of the system. This project positions City Light to meet the Federal Energy Regulatory Commission's vital communications systems requirements.

Information Technology ($19.8 Million) The major information technology projects included in the 2010-2015 CIP will maintain and upgrade data, software and equipment, which will enable City Light employees to perform critical utility functions in customer service, energy delivery and financial areas ($14.3 million). This project funds replacement and improvement of the Utility's information technology infrastructure. It provides applications, data storage, and print services to the utility, and supports activities and applications including e-mail, remote connectivity, the City InWeb, common applications such as Microsoft Office, City Light applications, UNIX services, and infrastructure change management. It also supports new information and software needs in strategic areas such as enterprise performance management ($1.6 million), energy trading and risk management ($1.6 million), and disaster recovery and business continuity ($1.4 million).

Security Improvements ($4.9 Million). The Security Improvements program plans, designs and implements projects to improve physical security of critical City Light facilities to restrict unauthorized access and criminal activities that could cause significant system damage, power outages and other disruptions to City Light's electrical system.

Outage Management ($4.8 Million). This project funds software and implementation of an Outage Management System (OMS). This project improves the Utility's outage response and restoration procedures as recommended in the "After Action Report" prepared by CH2M Hill and "Peer Review Report" by Davies Consulting, Inc.

16.4 Deferred Conservation Program Expenditures

Conservation resource programs offer financial incentives (rebates, discounts, loans, etc.) to customers who can produce energy savings by installing approved energy-saving equipment or weatherization measures or by designing a building to exceed energy code requirements. Program costs include program administration, audits and inspections, and the costs of designing and installing energy savings measures. The current expenditure level is consistent with the goal of the Utility's Five-Year Conservation Plan (which began in 2008) of achieving 163 average megawatts (aMW) of cumulative energy savings by 2012. The plan targets acquiring 10.8 aMW of energy savings in 2010, 11.5 aMW in 2011 and 13.0 aMW in 2012. The conservation forecast for 2013-2015 increases the annual energy savings acquired to 14 aMW and the expenditure forecast reflects this increase. The current plan increases from $30.1 million in 2010 to $41.2 million in 2013 and will increase with inflation thereafter.

16.5 Deferred O&M Expenses – Boundary Relicensing and Environmental Mitigation

In addition to making capital expenditures for environmental mitigation as part of its CIP, City Light also defers and capitalizes certain operations and maintenance expenditures for environmental mitigation. These expenditures are for mitigation measures similar to those included in the CIP and are similarly required under the terms of Federal licenses of the Skagit, South Fork Tolt and Boundary projects and in accordance with City Council resolution to protect endangered species in City Light generation areas. They differ from the expenditures in the CIP because they are for measures on land or structures belonging to entities other than City Light and involve payments to the owners. Recipients of these payments include a variety of nonprofit organizations and governmental agencies with which City Light has entered into contracts for environmental mitigation per the terms of relicensing settlement agreements. Expenditures are projected to be $10.8 million in 2010, $8.4 million in 2011 and to average about $1.0 million annually through 2019.

16.6 Deferred High Ross Payment

In setting rates for the 2000-2003 period, the Seattle City Council directed City Light to amortize the $21.8 million capital portion of the annual payment to B.C. Hydro under the High Ross

Agreement through 2035. Each year from 2000 through the final capital payment in 2020, $9.1 million of the annual payment will be deferred and $12.7 million will be recognized as an expense. From 2021 through 2035, the remaining balance of deferred costs will be amortized. The deferred portion of the payments to B.C. Hydro is treated as a component of capital requirements.

16.7 Funding for Capital Expenditures

Capital expenditures are funded from three major sources: 1) contributions, grants and fees from customers and other entities related to the assets or services being acquired as a result of the capital expenditure (discussed in detail in Chapter 14); 2) revenue from retail customer rates and other operating revenues (discussed in detail in Chapter 13); and 3) proceeds from debt (discussed in detail in chapter 15). The following table displays the amounts projected for each of these funding sources and the proportion of capital expenditures that they fund.

Table 16.2

Sources of Funding for Capital Expenditures
Dollars in Millions

	2010	2011	2012	2013	2014	2015
Cash from Operations	$54.0	$62.5	$83.6	$96.4	$107.4	$100.5
Cash from Contributions	$29.7	$30.7	$33.8	$32.0	$32.6	$33.8
Cash from Bond Proceeds *	$176.3	$148.7	$160.3	$146.7	$147.2	$115.5
% of Capital Req from Operations	21%	26%	30%	35%	37%	40%
% of Capital Req from Contributions	11%	13%	12%	12%	11%	14%
% of Capital Req from Bond Proceeds	68%	61%	58%	53%	51%	46%

* Bond Proceeds may be from bonds issued in a prior year.

Appendix 1 – Summary, Cash Flow and Indicator Reports - 2009-2019

Rate Study 2009_09_09

Million Dollars	2009	2010	2011	2012
Cash from Retail Power Sales before Discounts	540.1	587.8	629.6	690.3
Cash from Wholesale Power Sales, Net	69.2	120.0	116.1	90.5
Cash from All Other Sources	72.7	70.2	71.3	68.2
Cash to Power Contracts	260.8	293.4	284.1	274.4
Cash to Operations	193.4	201.7	217.8	219.0
Cash to Rate Discounts	5.5	6.1	6.5	7.0
Cash to Uncollectable Revenue	4.9	5.3	5.7	6.2
Cash to State Taxes and Franchise Payments	28.0	30.3	32.0	34.6
Cash Available for Debt Service	189.3	241.1	270.9	307.8
Cash to City Taxes	33.9	37.2	39.5	43.5
Cash to All Other Purposes	15.4	-0.8	9.5	9.8
Cash to Debt Service	144.8	150.7	159.4	171.0
Cash from Operations	-4.8	54.0	62.5	83.6
Cash from Contributions	25.0	29.7	30.7	33.8
Cash from Bond Proceeds	196.2	176.3	148.7	160.3
Cash to Capital, Conservation and Deferred O&M	216.4	260.1	242.0	277.7
Debt Service Coverage - Current Year	1.31	1.60	1.70	1.80
Debt Service Coverage - Average for ThreeYears	1.75	1.65	1.54	1.70
M$ Net Income	36.8	78.4	94.5	104.6
M$ Year-End Balance in Operating Cash Account	28.1	50.1	99.6	50.0
M$ Year-End Balance in Contingency Reserve Account	25.0	25.0	25.0	25.0
M$ Year-End Balance of Accumulated Net Income	830.9	909.3	1,003.7	1,108.3
M$ Year-End Balance of Debt Outstanding	1,383.1	1,502.3	1,622.6	1,649.6
Debt as a Percent of Total Capitalization	62%	62%	62%	60%
M$ of Cash fr Oper Needed for 95% Confidence w/o PRAM	11.7	70.4	76.7	76.9
M$ of Extra Confidence w/o PRAM	(16.5)	(16.4)	(14.1)	6.7
Probability Will Have Cash from Operations w/o PRAM	24%	87%	89%	97%
$ per MMBTU of Natural Gas	$3.50	$5.34	$6.31	$6.61
Month of Rate Change		Jan	Jan	Jan
Average Annual System Rate before Rate Change ($ per MWh)	$56.47	$57.47	$62.83	$66.92
Average Annual System Rate after Rate Change	$56.47	$62.53	$66.22	$71.33
Dollar Change in Average Annual System Rate	$0.00	$5.06	$3.38	$4.42
Percent Change in Average Annual System Rate	0.0%	8.8%	5.4%	6.6%
Average Residential Monthly Bill before Rate Change ($)	$43.90	$44.68	$48.85	$52.02
Average Residential Monthly Bill after Rate Change	$43.90	$48.62	$51.48	$55.46
Dollar Change in Average Residential Monthly Bill	$0.00	$3.93	$2.63	$3.43
Percent Change in Average Residential Monthly Bill	0.0%	8.8%	5.4%	6.6%
BPA Pass Through Effective Oct 1 ($ per MWh)	$1.00	$0.30	$0.70	$0.00
Percent Increase in Average Annual System Rate	1.8%	0.5%	1.1%	0.0%

Rate Study 2009_09_09

Million Dollars	2009	2010	2011	2012
Month of Rate Change	none	1	1	1
Debt Service Coverage Target	1.32	1.60	1.70	1.80
Rate Increase (Percent)				
Jan	0.00%	8.80%	5.39%	6.60%
Feb	0.00%	0.00%	0.00%	0.00%
Mar	0.00%	0.00%	0.00%	0.00%
Apr	0.00%	0.00%	0.00%	0.00%
May	0.00%	0.00%	0.00%	0.00%
Jun	0.00%	0.00%	0.00%	0.00%
Jul	0.00%	0.00%	0.00%	0.00%
Aug	0.00%	0.00%	0.00%	0.00%
Sep	0.00%	0.00%	0.00%	0.00%
Oct	0.00%	0.00%	0.00%	0.00%
Nov	0.00%	0.00%	0.00%	0.00%
Dec	0.00%	0.00%	0.00%	0.00%
Average Annual System Rate before Discounts ($ per MWh)	56.73	62.61	66.40	71.33
Jan	56.47	62.53	66.22	71.33
Feb	56.47	62.53	66.22	71.33
Mar	56.47	62.53	66.22	71.33
Apr	56.47	62.53	66.22	71.33
May	56.47	62.53	66.22	71.33
Jun	56.47	62.53	66.22	71.33
Jul	56.47	62.53	66.22	71.33
Aug	56.47	62.53	66.22	71.33
Sep	56.47	62.53	66.22	71.33
Oct	57.47	62.83	66.92	71.33
Nov	57.47	62.83	66.92	71.33
Dec	57.47	62.83	66.92	71.33
Energy Sales to Customer (MWh)	9,520,344	9,387,587	9,480,765	9,677,259
Jan	938,397	906,585	898,631	912,176
Feb	815,320	788,797	805,921	848,947
Mar	878,727	821,359	837,998	852,803
Apr	776,779	782,834	774,889	789,710
May	734,891	745,437	743,438	758,350
Jun	705,231	704,141	703,649	717,430
Jul	755,541	728,204	730,392	745,411
Aug	737,094	732,830	734,073	748,587
Sep	705,013	701,577	703,923	717,197
Oct	773,678	770,167	797,139	810,554
Nov	801,091	807,013	837,699	850,774
Dec	898,582	898,643	913,014	925,321
Cash from Retail Power Sales before Discounts	540.1	587.8	629.6	690.3
Jan	53.0	56.7	59.5	65.1
Feb	46.0	49.3	53.4	60.6
Mar	49.6	51.4	55.5	60.8
Apr	43.9	49.0	51.3	56.3
May	41.5	46.6	49.2	54.1
Jun	39.8	44.0	46.6	51.2
Jul	42.7	45.5	48.4	53.2
Aug	41.6	45.8	48.6	53.4
Sep	39.8	43.9	46.6	51.2
Oct	44.5	48.4	53.3	57.8
Nov	46.0	50.7	56.1	60.7
Dec	51.6	56.5	61.1	66.0

Seattle City Light

Rate Study 2009_09_09

Cash Flow 2008-2019

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Cash from Retail Power Sales before Discounts	550.0	540.1	587.8	629.6	690.3	717.5	715.6	773.1	801.0	830.5	880.8	908.5
Cash from Power Revenue Adjustment Mechanism	-	-	-	-	-	-	-	-	-	-	-	-
Cash from Wholesale Power Sales, Net	134.4	69.2	120.0	116.1	90.5	123.1	124.0	122.1	122.7	114.5	136.2	132.0
Cash from Power Contracts	37.5	24.0	22.3	20.4	19.0	19.3	20.0	19.4	15.6	16.3	16.8	17.2
Cash from Power Marketing, Net*	22.5	17.2	14.5	14.7	12.4	12.7	13.0	13.3	13.6	13.9	14.2	14.5
Cash from Other Outside Sources	23.0	26.5	29.2	28.8	28.0	28.8	56.2	30.3	31.1	31.9	32.8	33.6
Cash from Interest on Cash Accounts	6.0	4.9	4.2	7.3	9.0	9.4	11.1	10.4	11.8	11.5	11.4	11.2
Cash to Power Contracts	264.1	260.8	293.4	284.1	274.4	306.8	315.8	323.0	332.6	339.8	389.6	400.0
Cash to Production	30.4	28.3	34.5	35.4	36.2	37.1	38.0	38.9	39.8	40.7	41.6	42.5
Cash to Transmission	8.4	8.9	9.1	9.3	9.5	9.7	10.0	10.2	10.4	10.7	10.9	11.1
Cash to Distribution	60.7	58.2	51.6	62.4	65.4	66.9	68.6	70.2	71.7	73.3	74.9	76.5
Cash to Conservation	4.3	3.9	8.7	7.8	8.0	8.2	8.5	8.6	8.8	9.0	9.2	9.4
Cash to Customer Accounting	28.7	29.8	31.6	32.3	33.1	33.9	34.8	35.6	36.3	37.1	38.0	38.8
Cash to Administration	59.9	64.4	66.2	70.5	66.7	68.0	69.7	71.2	72.7	74.2	75.8	77.3
Cash to Rate Discounts	5.5	5.5	6.1	6.5	7.0	7.2	7.2	7.8	8.0	8.3	8.8	9.0
Cash to Uncollectable Revenue	4.7	4.9	5.3	5.7	6.2	6.5	6.4	7.0	7.2	7.5	7.9	8.2
Cash to State Taxes and Franchise Payments	28.0	28.0	30.3	32.0	34.6	35.7	35.9	38.2	39.5	40.8	42.8	44.1
Cash Available for Debt Service	278.6	189.3	241.1	270.9	307.8	330.7	345.0	358.2	368.7	377.3	392.6	400.0
Cash to City Taxes	33.9	33.9	37.2	39.5	43.5	45.0	44.9	48.4	50.1	51.8	54.8	56.4
Cash to Bond Reserve Account	-	-	-	-	-	-	-	-	-	-	-	-
Cash to Contingency Reserve Account	-	-	-	-	-	-	-	-	-	-	-	-
Cash to Balance Sheet Accounts	(1.3)	15.4	(0.8)	9.5	9.8	5.6	1.0	10.3	5.4	6.4	9.3	6.0
Cash to Debt Service	136.0	144.8	150.7	159.4	171.0	183.7	191.7	199.0	204.9	209.6	218.1	222.2
Cash from Operations	110.1	(4.8)	54.0	62.5	83.6	96.4	107.4	100.5	108.4	109.5	110.4	115.3
Cash from Contributions	24.5	25.0	29.7	30.7	33.8	32.0	32.6	33.8	36.7	37.2	37.7	37.0
Cash from Bond Proceeds **	48.3	196.2	176.3	148.7	160.3	146.7	147.2	115.5	184.9	169.7	162.0	157.1
Cash to Capital Projects	139.3	175.0	208.9	189.7	228.0	223.8	235.0	195.5	275.8	261.1	253.8	252.2
Cash to Conservation Projects	19.3	22.8	30.1	34.0	39.5	41.2	42.3	43.2	44.2	45.2	46.1	47.1
Cash to Deferred Project License Charges	15.1	9.4	11.9	9.2	1.1	0.9	0.9	1.9	1.0	1.0	1.0	1.0
Cash to Deferred High Ross Charges	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1	9.1

* Includes transactions such as basis sales, shaping sales and energy exchanges

** Bond Proceeds may be from bonds issued in a prior year. See page of Key Financial Indicators for the dollar value of bonds issued each year.

RateStudy2009_09_09 Finished 09/09/2009

Seattle City Light

Rate Study 2009_09_09

Key Financial Indicators

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Retail Sales (MWh)	9,708,507	9,520,344	9,387,587	9,480,765	9,677,259	9,750,957	9,833,746	9,900,817	10,014,814	10,073,730	10,163,141	10,251,242
Average System Rate before Discounts	$56.65	$56.73	$62.61	$66.40	$71.33	$73.58	$72.77	$78.09	$79.98	$82.44	$86.66	$88.62
% Change from Prior Year	0.3%	0.1%	10.4%	6.1%	7.4%	3.1%	-1.1%	7.3%	2.4%	3.1%	5.1%	2.3%
Consumer Price Index (2008=1)	1.000000	1.024999	1.050006	1.076102	1.102148	1.128507	1.156979	1.183061	1.209202	1.235716	1.262750	1.290334
Average Residential Monthly Bill before Discounts	$44.05	$44.11	$48.68	$51.63	$55.46	$57.20	$56.57	$60.71	$62.18	$64.10	$67.37	$68.90
Wholesale Power Revenue	207.5	98.4	154.4	155.0	135.2	172.4	175.3	174.9	178.5	172.2	192.2	189.9
Wholesale Power Expense	73.1	29.2	34.5	38.9	44.7	49.2	51.3	52.8	55.8	57.7	56.0	57.9
Net Wholesale Sales (MWh)	2,523,647	1,997,705	3,047,966	2,591,894	2,034,094	2,237,715	2,203,872	2,140,792	2,121,772	1,953,033	2,237,108	2,124,330
Net Wholesale Revenue per MWh	$53.27	$34.64	$39.36	$44.79	$44.49	$55.03	$56.26	$57.06	$57.82	$58.63	$60.90	$62.12
Price of Natural Gas (Actual $ per MMBTU)	$8.11	$3.50	$5.34	$6.31	$6.61	$7.90	$8.10	$8.28	$8.46	$8.65	$8.84	$9.03
Price of Natural Gas (2008 $ per MMBTU)	$8.11	$3.41	$5.09	$5.87	$6.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00	$7.00
Net Income	131.6	36.8	78.4	94.5	104.6	108.7	92.1	115.1	117.4	118.1	123.7	121.9
Debt Issued *	185.4	-	200.0	200.0	111.9	148.1	148.7	116.8	186.7	171.4	163.6	158.8
Year End Balance in Operating Cash Account	224.2	28.1	50.1	99.6	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
Year-End Balance in Bond Reserve Account	-	-	-	-	-	-	-	-	-	-	-	-
Year-End Balance in Contingency Reserve Account	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0	25.0
Year-End Balance of Accumulated Net Income	794.1	830.9	909.3	1,003.7	1,108.3	1,217.1	1,309.2	1,424.3	1,541.7	1,659.8	1,783.5	1,905.4
Year-End Balance of Debt Outstanding	1,457.4	1,383.1	1,502.3	1,622.6	1,649.6	1,704.4	1,752.7	1,764.0	1,842.6	1,905.8	1,956.7	2,002.0
Debt as a % of Total Capitalization	64.7%	62.5%	62.3%	61.8%	59.8%	58.3%	57.2%	55.3%	54.4%	53.4%	52.3%	51.2%
% of Capital Req from Operations	60%	-2%	21%	26%	30%	35%	37%	40%	33%	35%	36%	37%
% of Capital Req from Contributions	13%	12%	11%	13%	12%	12%	11%	14%	11%	12%	12%	12%
% of Capital Req from Bond Proceeds	26%	91%	68%	61%	58%	53%	51%	46%	56%	54%	52%	51%
Debt Service Coverage - Current Year	2.05	1.31	1.60	1.70	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Debt Service Coverage - Average for Three Years	2.10	1.75	1.65	1.54	1.70	1.77	1.80	1.80	1.80	1.80	1.80	1.80
Probability Will Have Cash from Operations	100.0%	24.3%	87.4%	89.2%	96.6%	95.8%	97.3%	95.7%	96.7%	96.0%	95.9%	96.5%
Debt Service Coverage Target	2.0	2.0	1.6	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
M$ of Debt Service Times Target	272.0	289.6	241.1	270.9	307.8	330.7	345.0	358.2	368.7	377.3	392.6	400.0
M$ of Cash Needed for 95% Confidence **	na	11.7	70.4	76.7	76.9	91.9	94.9	96.2	100.8	102.3	106.4	107.8
M$ of Extra Coverage	6.7	(100.3)	-	-	-	-	-	-	-	-	-	-
M$ of Extra Confidence	na	(16.5)	(16.4)	(14.1)	6.7	4.4	12.5	4.3	7.7	7.2	4.0	7.5

* The amount shown as debt issued after 2008 is the amount required to have the minimum amount of Operating Cash specified by the Financial Policy Resolution ($30 million) at the end of the year.
* The actual amount of debt issued in any year will depend on actual operating results to that point in time and may be very different than the amount listed for that year.
** This is the Average Cash from Operations needed to be 95% Confident that the Actual Cash from Operations under any Retail/Wholesale Revenue scenario will be greater than zero.

RateStudy2009_09_09 Finished 09/09/2009

Appendix 2 – Financial Planning Model Forecast - 2009 - 2014

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
Finished 09/09/2009

- - - - - - - - - - T A B L E   O F   C O N T E N T S - - - - - - - - - -

Note, the Executive Decisions are put into three lines; two in distribution (Table 1.12) and one in Other Revenue (Table 1.14, Water Heater Rentals)

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09

Statement of Operations
(Dollars)

Table 1.01

	2009	2010	2011	2012	2013	2014
Operating Revenue	716,990,224	837,461,383	875,730,868	901,656,452	973,595,056	977,386,567
Retail Power Sales inside System	538,044,802	585,237,568	626,728,681	687,028,483	714,046,784	712,307,604
Revenue from Residential Customers	190,662,926	205,642,969	219,234,531	238,960,767	245,808,651	242,578,408
Revenue from Non-Residential Customers	347,381,876	379,594,599	407,494,151	448,067,716	468,238,133	469,729,197
Retail Power Sales outside System	0	0	0	0	0	0
Wholesale Power Sales	93,077,417	144,431,174	144,762,111	124,660,535	161,626,718	164,266,003
Other Power Sales	60,354,570	79,653,449	76,162,162	62,832,971	70,118,115	72,308,204
Transmission Services	4,493,661	4,579,411	4,693,008	4,806,594	4,921,652	5,045,451
Other Revenue	21,019,774	23,559,782	23,384,905	22,327,868	22,881,787	23,459,303
Operating Expenses	654,146,706	735,185,459	748,996,493	767,965,619	828,949,043	855,572,930
Operations and Maintenance Expenses	511,693,912	579,035,094	583,502,356	589,043,770	640,490,532	660,735,596
Generation	29,689,054	37,821,515	38,808,902	41,787,780	42,766,680	43,823,260
Long-Term Purchased Power	198,351,442	228,230,102	221,070,547	207,496,390	240,770,734	249,064,200
Short-Term Wholesale Power Purchases	29,170,136	34,457,803	38,925,062	44,651,157	49,236,710	51,286,947
Power-Related Wholesale Purchases	27,370,915	35,895,845	27,304,598	28,312,667	32,933,837	33,777,224
Deferred Power Expenses	0	0	0	0	0	0
Other Power Costs	9,502,527	9,735,323	9,963,093	10,199,348	10,441,045	10,691,001
Transmission	8,951,350	9,205,191	9,415,939	9,626,149	9,841,608	10,061,110
Wheeling	40,214,695	48,159,603	48,393,192	49,549,674	50,787,422	51,955,441
Distribution	58,167,623	51,617,066	62,371,739	65,366,864	66,930,259	68,618,759
Conservation	15,958,592	21,786,311	22,296,506	24,132,913	26,173,198	28,195,179
Customer Accounting	34,701,094	36,851,696	38,011,354	39,339,969	40,376,043	41,213,579
Administration	59,616,485	65,274,640	66,941,425	68,580,857	70,232,998	72,048,896
Taxes	61,997,078	67,525,892	71,512,374	78,073,044	80,685,250	80,795,260
Depreciation	80,455,716	88,624,473	93,981,763	100,848,805	107,773,261	114,042,074
Net Operating Revenue	62,843,518	102,275,924	126,734,375	133,690,833	144,646,013	121,813,637
Nonoperating Revenues (Expenses)	-62,437,876	-68,666,299	-71,173,965	-71,185,047	-73,671,956	-68,224,976
Investment Income	4,943,975	4,208,965	7,322,873	8,971,198	9,435,389	11,074,044
Gain (Loss) on Sale of Property	1,000,000	1,024,397	1,049,856	1,075,267	1,100,983	8,528,759
Other Income (Expense), Net	-376,344	-266,502	-272,805	-279,258	-285,863	-292,625
Interest Expense	-66,409,827	-72,124,601	-77,789,692	-79,485,864	-82,499,755	-86,148,627
Amortization of Debt Expense	-1,595,680	-1,508,558	-1,484,197	-1,466,389	-1,422,711	-1,386,527
Fees, Grants, and Transfers	36,409,597	44,800,188	38,895,836	42,107,708	37,766,137	38,505,188
Suburban Undergrounding	5,346,805	11,313,425	7,211,923	2,671,406	0	0
Capital - Cash	24,889,490	27,428,075	26,017,295	33,822,010	32,017,569	32,611,596
Capital - Noncash	5,221,303	5,348,689	5,481,618	5,614,292	5,748,568	5,893,592
Operating	952,000	710,000	185,000	0	0	0
Net Income (Loss)	36,815,240	78,409,814	94,456,246	104,613,494	108,740,194	92,093,849
Check First Net Income	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.02

Summary of Historical and Projected Operating Results

	2009	2010	2011	2012	2013	2014
Operating Revenue	716,990,224	837,461,383	875,730,868	901,656,452	973,595,056	977,386,567
Retail Power Sales inside System	538,044,802	585,237,568	626,728,681	687,028,483	714,046,784	712,307,604
Revenue from Residential Customers	190,662,926	205,642,969	219,234,531	238,960,767	245,808,651	242,578,408
Revenue from Non-Residential Customers	347,381,876	379,594,599	407,494,151	448,067,716	468,238,133	469,729,197
Retail Power Sales outside System	0	0	0	0	0	0
Wholesale Power Sales	93,077,417	144,431,174	144,762,111	124,660,535	161,626,718	164,266,003
Other Power Sales	60,354,570	79,653,449	76,162,162	62,832,971	70,118,115	72,308,204
Transmission Services	4,493,661	4,579,411	4,693,008	4,806,594	4,921,652	5,045,451
Other Revenue	21,019,774	23,559,782	23,384,905	22,327,868	22,881,787	23,459,303
Operating Expense	539,742,430	609,378,733	615,484,603	623,651,014	676,210,815	696,613,027
Generation	29,689,054	37,821,515	38,808,902	41,787,780	42,766,680	43,823,260
Long-Term Purchased Power	198,351,442	228,230,102	221,070,547	207,496,390	240,770,734	249,064,200
Short-Term Wholesale Power Purchases	29,170,136	34,457,803	38,925,062	44,651,157	49,236,710	51,286,947
Power-Related Wholesale Purchases	27,370,915	35,895,845	27,304,598	28,312,667	32,933,837	33,777,224
Deferred Power Expenses	0	0	0	0	0	0
Other Power Costs	9,502,527	9,735,323	9,963,093	10,199,348	10,441,045	10,691,001
Transmission	8,951,350	9,205,191	9,415,939	9,626,149	9,841,608	10,061,110
Wheeling	40,214,695	48,159,603	48,393,192	49,549,674	50,787,422	51,955,441
Distribution	58,167,623	51,617,066	62,371,739	65,366,864	66,930,259	68,618,759
Conservation	15,958,592	21,786,311	22,296,506	24,132,913	26,173,198	28,195,179
Customer Accounting	34,701,094	36,851,696	38,011,354	39,339,969	40,376,043	41,213,579
Administration	59,616,485	65,274,640	66,941,425	68,580,857	70,232,998	72,048,896
Taxes Excluding City Taxes	28,048,518	30,343,639	31,982,247	34,607,244	35,720,282	35,877,432
Net Operating Revenue	177,247,794	228,082,650	260,246,265	278,005,437	297,384,242	280,773,539
Amortization	10,036,447	10,575,553	7,715,356	22,432,009	24,390,563	26,333,080
Other Noncash Expense, Net	-4,907,949	-3,847,718	-6,164,210	-3,484,606	-2,631,372	-1,978,750
Investment Income	4,943,975	4,208,965	7,322,873	8,971,198	9,435,389	11,074,044
Other Income	-376,344	-266,502	-272,805	-279,258	-285,863	-292,625
Proceeds from Sale of Property	1,000,000	1,024,397	1,049,856	1,075,267	1,100,983	27,728,759
Proceeds from Suburban Undergrounding	417,227	621,676	841,356	1,094,824	1,263,432	1,358,709
Operating Fees and Grants	952,000	710,000	185,000	0	0	0
Cash from (to) Debt Service Pmt Account	0	0	0	0	0	0
Amount Available for Debt Service	189,313,151	241,109,022	270,923,690	307,814,871	330,657,375	344,996,756
Debt Service	144,805,234	150,693,139	159,366,876	171,008,262	183,698,542	191,664,865
1st-Lien Bonds	144,805,234	150,693,139	159,366,876	171,008,262	183,698,542	191,664,865
2nd-Lien Bonds	0	0	0	0	0	0
Revenue Anticipation Notes	0	0	0	0	0	0
Bank Notes	0	0	0	0	0	0
Debt Service Coverage Ratios						
1st-Lien Bonds	1.3070	1.6000	1.7000	1.8000	1.8000	1.8000
1st & 2nd-Lien Bonds	1.3070	1.6000	1.7000	1.8000	1.8000	1.8000
Debt Service as Pct of Revenue from Customers	26.90	25.70	25.40	24.90	25.70	26.90
Average Retail Revenue per MWh ($/MWh)	56.52	62.34	66.11	70.99	73.23	72.44
Check Amount Available for Debt Service	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.03 **Funds Required/Provided**

	2009	2010	2011	2012	2013	2014
Total Funds Required	216,369,570	260,077,435	241,962,319	277,709,765	275,039,183	287,247,744
Capital Expenditures	206,738,347	249,857,127	232,146,953	268,342,684	265,935,850	278,144,411
Capital Improvement Projects	175,036,670	208,949,320	189,703,776	227,998,546	223,833,693	234,986,006
Generation	23,458,197	26,025,197	35,767,218	81,005,771	78,072,776	86,135,889
Transmission	1,544,564	3,500,184	3,758,307	1,562,140	1,599,802	1,638,751
Distribution	126,367,119	159,916,424	132,604,209	136,917,465	146,246,513	164,426,094
General Plant	23,666,790	42,724,106	38,652,239	33,846,342	22,785,012	8,894,828
Expenditures Not Yet Distributed	0	-23,216,591	-21,078,197	-25,333,172	-24,870,410	-26,109,556
Conservation	22,797,752	30,080,469	33,988,744	39,496,779	41,234,532	42,274,787
Deferred O&M Costs	8,903,925	10,827,338	8,454,432	847,359	867,625	883,618
Deferred High Ross Charges	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333
Deferred Power Charges (Expenses)	0	0	0	0	0	0
Capitalized Interest	0	0	0	0	0	0
City Tax on Suburban Undergrounding	320,808	678,806	432,715	160,284	0	0
State Tax on Suburban Undergrounding	207,082	438,169	279,318	103,464	0	0
Total Funds Provided	216,369,570	260,077,435	241,962,319	277,709,765	275,039,183	287,247,744
Cash from Operations	-4,817,194	54,018,178	62,537,823	83,581,066	96,351,132	107,428,125
Plus Amount Available for Debt Service	189,313,151	241,109,022	270,923,690	307,814,871	330,657,375	344,996,756
Minus Debt Service	144,805,234	150,693,139	159,366,876	171,008,262	183,698,542	191,664,865
Minus City Taxes	33,948,560	37,182,253	39,530,127	43,465,800	44,964,968	44,917,829
Minus Add to Bond Reserve Fund	0	0	0	0	0	0
Minus Other Funds Required, Net	15,376,551	-784,548	9,488,863	9,759,743	5,642,734	985,938
Proceeds from Contributions	25,019,023	29,728,075	30,749,985	33,822,010	32,017,569	32,611,596
Capital Fees and Grants	24,889,490	27,428,075	26,017,295	33,822,010	32,017,569	32,611,596
Customer Payments for Conservation	0	0	0	0	0	0
BPA Payments for Conservation Offset	0	0	0	0	0	0
BPA Payments for Conservation Deferred	129,533	2,300,000	4,732,690	0	0	0
Proceeds from (to) Working Capital Account	196,167,741	-22,025,007	-49,523,468	49,604,907	0	0
Proceeds from Sale of Bonds	0	198,356,189	198,197,979	110,701,781	146,670,482	147,208,023
Plus Proceeds from 1-st Lien Bonds	0	200,000,000	200,000,000	111,918,993	148,146,173	148,707,411
Plus Proceeds from 2-nd Lien Bonds	0	0	0	0	0	0
Plus Proceeds from Ran (net)	0	0	0	0	0	0
Plus Proceeds from (to) Bank Notes	0	0	0	0	0	0
Minus Debt Issue Costs	0	587,602	609,931	632,499	655,269	678,858
Minus Surety Bond Premium	0	96,209	232,090	47,501	109,321	106,735
Minus Discount on Debt Issued	0	960,000	960,000	537,211	711,102	713,796
Minus Charge on Refunded Debt	0	0	0	0	0	0
Pct of Capital Expenditures Financed with Funds Available From Current Operations	-2.23	20.77	25.85	30.10	35.03	37.40
Probability Will Have Cash from Operations	24	87	89	97	96	97
A&G Expenses Recognized as Capital Expeditures	26,392,281	27,038,194	27,667,311	28,321,626	28,990,941	29,683,452

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.04 **Net Earnings**

	2009	2010	2011	2012	2013	2014
Amount Available for Debt Service	189,313,151	241,109,022	270,923,690	307,814,871	330,657,375	344,996,756
plus Noncash Revenue, Net	4,907,949	3,847,718	6,164,210	3,484,606	2,631,372	1,978,750
plus Gain on Sale of Property	1,000,000	1,024,397	1,049,856	1,075,267	1,100,983	8,528,759
minus Proceeds from Sale of Property	1,000,000	1,024,397	1,049,856	1,075,267	1,100,983	27,728,759
minus Proceeds from Suburban Undergrounding	417,227	621,676	841,356	1,094,824	1,263,432	1,358,709
minus Cash from (to) Debt Service Pmt Account	0	0	0	0	0	0
Minus City Taxes	33,948,560	37,182,253	39,530,127	43,465,800	44,964,968	44,917,829
Minus Interest Expense	66,409,827	72,124,601	77,789,692	79,485,864	82,499,755	86,148,627
1st-Lien Bonds	73,067,265	77,937,749	83,741,338	85,954,846	89,498,450	93,014,685
2nd-Lien Bonds	0	0	0	0	0	0
Revenue Anticipation Notes	0	0	0	0	0	0
Bank Notes	0	0	0	0	0	0
AFUDC on Projects	-6,657,438	-5,813,148	-5,951,645	-6,468,982	-6,998,695	-6,866,059
Minus Amortization of Debt Expense	1,595,680	1,508,558	1,484,197	1,466,389	1,422,711	1,386,527
Amort of Debt Issue Charges	1,132,923	1,071,067	1,034,439	1,004,300	965,920	928,904
Amort of Discount on Debt Issued	-3,085,046	-2,916,607	-2,703,984	-2,491,795	-2,291,728	-2,079,204
Amort of Charge on Refunded Debt	3,547,804	3,354,098	3,153,741	2,953,884	2,748,519	2,536,827
Minus Amortization	10,036,447	10,575,553	7,715,356	22,432,009	24,390,563	26,333,080
BPA Payments for Conservation	-5,915,809	-6,513,940	-10,911,895	0	0	0
High Ross Expenditures	347,404	347,404	347,404	347,404	347,404	347,404
BPA Exit Fee	0	0	0	0	0	0
Conservation	12,038,040	13,045,415	14,449,768	16,086,175	17,925,292	19,739,197
Vehicles and Boats	2,112,060	2,163,750	2,214,095	2,266,457	2,320,020	2,375,439
Relicensing Mitigation	1,355,465	1,433,639	1,516,697	3,632,686	3,698,562	3,771,755
Puget Stillwater Sub	99,286	99,286	99,286	99,286	99,286	99,286
Puget Intertie	0	0	0	0	0	0
Georgetown	0	0	0	0	0	0
Minus Depreciation	80,455,716	88,624,473	93,981,763	100,848,805	107,773,261	114,042,074
Production Plant	12,910,655	15,124,995	15,923,126	16,806,059	18,519,426	19,152,373
Transmission Plant	3,591,269	4,191,089	4,400,914	4,628,490	4,862,105	5,222,409
Distribution Plant	46,751,124	52,071,220	56,757,982	62,865,076	68,245,045	73,927,646
General Plant	17,202,667	17,624,112	18,024,930	18,447,893	18,882,124	19,324,751
Expenditures Not Yet Distributed	0	-386,943	-1,125,190	-1,898,712	-2,735,439	-3,585,105
Plus Fees, Grants and Transfers	35,457,597	44,090,188	38,710,836	42,107,708	37,766,137	38,505,188
Suburban Undergrounding	5,346,805	11,313,425	7,211,923	2,671,406	0	0
Contributions in Aid of Construction-Cash	21,057,808	26,594,243	25,404,506	33,429,985	31,476,247	31,823,491
Contributions in Aid of Construction-Noncash	5,221,303	5,348,689	5,481,618	5,614,292	5,748,568	5,893,592
Capital Grants from Sound Transit	3,491,747	713,114	502,346	294,559	447,054	691,459
Capital Grants from FEMA	300,000	0	0	0	0	0
Other Capital Fees and Grants	39,935	120,717	110,443	97,466	94,268	96,646
Capital Transfers	0	0	0	0	0	0
Net Income	36,815,240	78,409,814	94,456,246	104,613,494	108,740,194	92,093,849
Check Second Net Income	0	0	0	0	0	0
Check Funds Required/Provided	0	0	0	0	0	0
Check Funds Provided from Current Operations	0	0	0	0	0	0
Check Funds Provided from Contributions	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.05 **Assets and Liabilities**

	2009	2010	2011	2012	2013	2014
Assets	2,413,226,911	2,614,144,887	2,826,286,137	2,957,690,087	3,120,122,063	3,262,016,971
Plant Investment less Depreciation	1,776,910,078	1,906,133,726	2,010,975,622	2,147,842,884	2,274,231,283	2,386,260,131
Deferred Conservation Expenditures	160,271,940	177,306,994	196,845,971	220,256,574	243,565,814	266,101,405
Customer Conservation Loans Outstanding	0	0	0	0	0	0
Materials and Supplies	26,274,998	26,896,480	27,532,662	28,183,891	28,850,524	29,532,924
Interest-Earning Accounts	53,056,432	75,081,439	124,604,907	75,000,000	75,000,000	75,000,000
Bond Reserve Fund	0	0	0	0	0	0
Low Income Account	0	0	0	0	0	0
Debt Service Pmt Account	0	0	0	0	0	0
Working Capital Account	53,056,432	75,081,439	124,604,907	75,000,000	75,000,000	75,000,000
Accrued Unbilled Revenue	52,610,258	56,009,086	59,296,969	62,831,907	64,578,457	64,245,678
Accounts Receivable	85,751,720	80,946,863	86,511,661	92,085,237	95,314,789	95,951,105
Receivable from Suburban Undergrounding	30,172,873	41,981,597	49,064,197	50,904,527	49,641,095	48,282,386
Special Expenditures	61,445,614	70,491,910	77,082,241	73,949,510	70,771,169	67,535,628
Receivable for Redding Exchange	0	0	0	0	0	0
Receivable for SMUD Exchange	0	0	0	0	0	0
Receivable for Lucky Peak Exchange	0	0	0	0	0	0
Deferred Debt Issue Expense	9,514,148	9,126,892	8,934,474	8,610,175	8,408,845	8,265,534
Deferred Power Costs Balance	91,033,330	100,136,663	109,239,996	118,343,329	127,446,662	136,549,995
Receivable for Seasonal Exchange	-12,651,667	-8,803,949	-2,639,739	844,868	3,476,239	5,454,989
Other Assets	78,837,187	78,837,187	78,837,187	78,837,187	78,837,187	78,837,187
Liabilities	-2,413,226,911	-2,614,144,887	-2,826,286,137	-2,957,690,087	-3,120,122,063	-3,262,016,971
Accumulated Net Earnings	830,868,588	909,278,402	1,003,734,648	1,108,348,142	1,217,088,337	1,309,182,186
BPA Payments for Conservation	10,393,144	6,179,205	0	0	0	0
1st-Lien Bonds	1,383,050,000	1,502,315,000	1,622,640,000	1,649,630,156	1,704,367,722	1,752,673,826
2nd-Lien Bonds	0	0	0	0	0	0
Interest Payable on 1st-Lien Bonds	30,981,544	38,961,154	43,010,615	42,886,036	42,094,552	43,845,681
Interest Payable on 2nd-Lien Bonds	-338,500	-338,500	-338,500	-338,500	-338,500	-338,500
Unamortized Bond Discounts (Net)	25,907,841	22,031,234	18,367,250	15,338,244	12,335,415	9,542,415
Deferred Charge on Refunded Debt	-29,794,020	-26,439,922	-23,286,180	-20,332,296	-17,583,777	-15,046,950
Revenue Anticipation Notes Payable	0	0	0	0	0	0
Bank Notes Payable	0	0	0	0	0	0
Other Liabilities	162,158,314	162,158,314	162,158,314	162,158,314	162,158,314	162,158,314
Outstanding 1st-Lien and 2nd-Lien Bonds	1,383,050,000	1,502,315,000	1,622,640,000	1,649,630,156	1,704,367,722	1,752,673,826
Total Outstanding Debt	1,383,050,000	1,502,315,000	1,622,640,000	1,649,630,156	1,704,367,722	1,752,673,826
Accumulated Equity	830,868,588	909,278,402	1,003,734,648	1,108,348,142	1,217,088,337	1,309,182,186
Total Capitalization	2,213,918,588	2,411,593,402	2,626,374,638	2,757,978,289	2,921,456,059	3,061,856,011
Debt as Pct of Total Capitalization	62.500	62.300	61.800	59.800	58.300	57.200
Avg Life of 1st-Lien Debt Outstanding	9.100	9.600	9.900	9.800	9.900	10.000
Avg Life of 1st & 2nd-Lien Debt Outstanding	9.100	9.600	9.900	9.800	9.900	10.000
2nd-Lien Debt as Pct of 1st-Lien Debt	0.000	0.000	0.000	0.000	0.000	0.000
Total Accounts Receivable	85,751,720	80,946,863	86,511,661	92,085,237	95,314,789	95,951,105
Receivables from Cus. (Amt. billed in Dec.)	46,761,657	51,213,526	56,008,905	60,835,851	63,296,115	63,107,451
Receivables from Other Sources	38,990,063	29,733,337	30,502,756	31,249,387	32,018,674	32,843,654
Check Accounts Receivable	0	0	0	0	0	0
Contingency Reserve Account Balance	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000	25,000,000

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.06 **Purchased Power Revenue and Expenses**

	2009	2010	2011	2012	2013	2014
Revenue from Wholesale Power Sales	93,077,417	144,431,174	144,762,111	124,660,535	161,626,718	164,266,003
Wholesale Revenues excl Hydro Opt Benefit	98,377,417	154,431,174	155,010,639	135,157,112	172,374,339	175,284,762
Hydro Optimization Benefit	0	0	0	0	0	0
Booked Out Long Term Purchases	-5,300,000	-10,000,000	-10,248,527	-10,496,576	-10,747,621	-11,018,759
Revenue from Other Power Sales	60,354,570	79,653,449	76,162,162	62,832,971	70,118,115	72,308,204
BPA Conservation & Renewables Credit	2,497,809	2,486,316	1,864,737	0	0	0
BPA Payments for Conservation	5,915,809	6,513,940	10,911,895	0	0	0
Integration & Exchange of Wind Resources	0	0	0	0	0	0
Forced Outage Reserve for Box Canyon	0	0	0	0	0	0
Article 49 Sales to PO County	1,721,879	1,763,888	1,807,726	1,851,479	1,895,760	1,943,586
Sale of Centralia	0	0	0	0	0	0
Sale of CSPE to Calif	0	0	0	0	0	0
Sale of CSPE to Puget	0	0	0	0	0	0
Sale of Capacity to PG&E	0	0	0	0	0	0
Sales from Priest Rapids	5,355,330	8,590,472	7,158,827	7,433,270	7,667,719	8,239,662
Interchange Delivered	0	0	0	0	0	0
Seasonal Exchange Delivered	-887,489	4,543,765	4,219,080	4,318,193	4,424,981	4,537,676
Payment from General Fund	0	0	0	0	0	0
Exchange Energy Delivered to SMUD	0	0	0	0	0	0
Lucky Peak Exchange Energy Delivered	0	0	0	0	0	0
Exchange Energy Delivered to Redding	998,933	2,944,317	3,319,389	3,455,268	4,093,352	4,192,880
Basis Sales	13,158,328	19,406,943	22,055,689	22,936,717	27,429,312	28,133,832
Other Services	31,593,971	33,403,808	24,824,820	22,838,044	24,606,991	25,260,568
Expense for Wholesale Power Purchases	29,170,136	34,457,803	38,925,062	44,651,157	49,236,710	51,286,947
Power-Related Wholesale Purchases	27,370,915	35,895,845	27,304,598	28,312,667	32,933,837	33,777,224
Basis Purchases	12,431,011	17,906,943	20,518,410	21,362,231	25,817,169	26,481,018
Lucky Peak Exchange Energy Received	0	0	0	0	0	0
Other Services	14,939,903	17,988,902	6,786,187	6,950,436	7,116,668	7,296,206
Payments for Interrupting Customers	0	0	0	0	0	0
Storage and Load Factoring	0	0	0	0	0	0
Ross Overdraft Contract	0	0	0	0	0	0
Deferred Power Expenses	0	0	0	0	0	0
Expense for Other Power Purchases	198,351,442	228,230,102	221,070,547	207,496,390	240,770,734	249,064,200
Bonneville Power Administration	153,704,178	166,436,060	164,679,154	152,591,141	154,636,295	159,966,886
Amortization of BPA Exit Fee Expenditures	0	0	0	0	0	0
Box Canyon	0	0	0	0	0	0
Encroachment on Box Canyon	0	-1,129,295	-1,157,361	-1,185,373	-1,213,723	-1,244,343
Priest Rapids	1,788,917	12,441,250	2,717,372	2,874,090	2,950,195	3,350,249
Entl/Supp Capacity	0	0	0	0	0	0
High Ross Contract	13,067,224	13,075,067	13,083,320	13,091,517	13,099,812	13,108,772
Amortization of High Ross Expenditures	347,404	347,404	347,404	347,404	347,404	347,404
CSPE	0	0	0	0	0	0
Grand Coulee	5,237,828	5,014,000	4,735,764	4,778,360	4,822,046	4,866,850
Lucky Peak	5,250,836	6,065,000	6,211,794	6,360,358	6,520,816	6,667,811
Rocky Brook	0	0	0	0	0	0
Metro Cogen	0	0	0	0	0	0
Kalamath Falls	0	0	0	0	0	0
SPI Purchase	1,341,688	1,716,407	1,746,444	1,781,876	1,808,105	1,839,746
Exchange Energy Received From SMUD	4,034,069	5,705,409	6,465,691	6,740,402	8,034,534	8,236,280
Wind Resources	13,894,463	15,712,024	16,102,515	16,492,252	16,886,686	17,312,702
Integration & Exchange of Wind Resources	5,125,502	5,451,587	5,587,075	5,722,302	6,000,975	6,451,984
IRP Resources	704,671	2,870,691	4,115,945	4,219,956	32,080,349	32,804,559
Resources for Peak Periods	0	0	0	0	0	0
Interchange Received	0	0	0	0	0	0
Seasonal Exchange Received	1,679,973	5,101,549	6,973,453	4,419,647	5,236,141	6,061,289
Exchange Energy Received from Redding	998,933	2,944,317	3,319,389	3,455,268	4,093,352	4,192,880
BPA Credit for South Fork Tolt	-3,524,244	-3,521,368	-3,608,885	-3,696,232	-3,784,633	-3,880,111
Booked Out Long Term Purchases	-5,300,000	-10,000,000	-10,248,527	-10,496,576	-10,747,621	-11,018,759
Receivable/Payable fr/to Power Market	63,907,281	109,973,371	105,837,050	80,009,378	112,390,008	112,979,056

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)
Purchased Power Revenue and Expenses - Cash

Table 1.07

	2009	2010	2011	2012	2013	2014
Revenue - Power Contracts	13,099,262	16,362,044	14,440,174	12,980,981	13,348,112	14,063,359
Article 49 Sales to PO County	1,721,879	1,763,888	1,807,726	1,851,479	1,895,760	1,943,586
Seattle Share of Priest Rapids Revenue	5,355,330	8,590,472	7,158,827	7,433,270	7,667,719	8,239,662
BPA Credit for South Fork Tolt	3,524,244	3,521,368	3,608,885	3,696,232	3,784,633	3,880,111
BPA Credit for Conservation	2,497,809	2,486,316	1,864,737	0	0	0
Sale of Energy fr Centralia	0	0	0	0	0	0
Sale of Energy fr CSPE to Calif	0	0	0	0	0	0
Sale of Energy fr CSPE to Puget	0	0	0	0	0	0
Revenue - Power Marketing Net	10,365,566	11,383,406	8,884,646	11,942,226	12,547,052	12,923,984
Transmission Services	4,493,661	4,579,411	4,693,008	4,806,594	4,921,652	5,045,451
Basis Sales Net	727,317	1,500,000	1,537,279	1,574,486	1,612,143	1,652,814
Other Services Net	5,144,588	5,303,995	2,654,359	5,561,145	6,013,257	6,225,719
Integration & Exchange of Wind Resources	0	0	0	0	0	0
Forced Outage Reserve for Box Canyon	0	0	0	0	0	0
Sale of Capacity to PG&E	0	0	0	0	0	0
Interchange Net	0	0	0	0	0	0
Payment from General Fund	0	0	0	0	0	0
Minus						
Resources Acquired for Peak Periods	0	0	0	0	0	0
Payments for Interrupting Customers	0	0	0	0	0	0
Storage and Load Factoring	0	0	0	0	0	0
Ross Overdraft Contract	0	0	0	0	0	0
Expense - Long-Term Purchased Power	200,115,307	228,782,086	218,979,384	207,911,850	238,805,280	246,369,560
Bonneville Power Administration	153,704,178	166,436,060	164,679,154	152,591,141	154,636,295	159,966,886
Wind Resources	19,019,965	21,163,611	21,689,590	22,214,554	22,887,662	23,764,686
High Ross Contract	13,067,224	13,075,067	13,083,320	13,091,517	13,099,812	13,108,772
Lucky Peak	5,250,836	6,065,000	6,211,794	6,360,358	6,520,816	6,667,811
Grand Coulee	5,237,828	5,014,000	4,735,764	4,778,360	4,822,046	4,866,850
Priest Rapids	1,788,917	12,441,250	2,717,372	2,874,090	2,950,195	3,350,249
SPI Purchase	1,341,688	1,716,407	1,746,444	1,781,876	1,808,105	1,839,746
IRP Resources	704,671	2,870,691	4,115,945	4,219,956	32,080,349	32,804,559
Box Canyon	0	0	0	0	0	0
CSPE	0	0	0	0	0	0
Entl/Supp Capacity	0	0	0	0	0	0
Rocky Brook	0	0	0	0	0	0
Metro Cogeneration	0	0	0	0	0	0
Kalamath Falls	0	0	0	0	0	0
Basis Sales Net	727,317	1,500,000	1,537,279	1,574,486	1,612,143	1,652,814
Plus - Revenue for Basis Sales	13,158,328	19,406,943	22,055,689	22,936,717	27,429,312	28,133,832
Minus - Expense for Basis Purchases	12,431,011	17,906,943	20,518,410	21,362,231	25,817,169	26,481,018
Other Services Net	5,144,588	5,303,995	2,654,359	5,561,145	6,013,257	6,225,719
Plus - Revenue from Other Power Sales	31,593,971	33,403,808	24,824,820	22,838,044	24,606,991	25,260,568
Plus - Revenue from Other Power Sales	0	0	0	0	0	0
Minus - Expense for Other Power Purchase	14,939,903	17,988,902	6,786,187	6,950,436	7,116,668	7,296,206
Minus - Expense for Other Power Purchase	0	0	0	0	0	0
Minus - Exp for EE from SMUD Exchange	4,034,069	5,705,409	6,465,691	6,740,402	8,034,534	8,236,280
Plus - Other Noncash Expense (v440)	-7,475,411	-4,405,501	-8,918,583	-3,586,061	-3,442,531	-3,502,363
Other Noncash Expense, Net (Table 1.02)	-4,907,949	-3,847,718	-6,164,210	-3,484,606	-2,631,372	-1,978,750
Plus - Other Noncash Expense (v440)	-7475411	-4405501	-8918583	-3586061	-3442531	-3502363
Plus - Exp for EE fr NCPA Exchange	1,679,973	5,101,549	6,973,453	4,419,647	5,236,141	6,061,289
Plus - Exp for EE fr SMUD Exchange	4,034,069	5,705,409	6,465,691	6,740,402	8,034,534	8,236,280
Plus - Exp for EE fr Redding Exchange	998,933	2,944,317	3,319,389	3,455,268	4,093,352	4,192,880
Plus - Exp for EE fr Lucky Peak Exchange	0	0	0	0	0	0
Minus - Rev for EE to NCPA Exchange	-887,489	4,543,765	4,219,080	4,318,193	4,424,981	4,537,676
Minus - Rev for EE to SMUD Exchange	4,034,069	5,705,409	6,465,691	6,740,402	8,034,534	8,236,280
Minus - Rev for EE to Redding Exchange	998,933	2,944,317	3,319,389	3,455,268	4,093,352	4,192,880
Minus - Rev for EE to Lucky Peak Exchange	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
($/MWH)

Table 1.08 **Purchased Power Prices in Dollars/Mwh**

	2009	2010	2011	2012	2013	2014
Bonneville Power Administration	28.24	29.51	30.49	30.38	31.24	31.98
Box Canyon	N/A	N/A	N/A	N/A	N/A	N/A
Priest Rapids	54	54	113	119	122	139
High Ross Contract	43	43	43	43	43	43
Grand Coulee	21	21	20	20	20	20
Lucky Peak	17	21	21	22	22	23
Metro Cogen	N/A	N/A	N/A	N/A	N/A	N/A
Kalamath Falls	N/A	N/A	N/A	N/A	N/A	N/A
SPI Purchase	67	65	66	68	69	70
Combustion Turbine Two	N/A	N/A	N/A	N/A	N/A	N/A
Wind Resources	37	39	40	41	42	43
IRP Resources	83	57	52	53	71	73
Interchange Received	N/A	N/A	N/A	N/A	N/A	N/A
Interchange Delivered	N/A	N/A	N/A	N/A	N/A	N/A
Purchases from Power Market	34	43	51	53	64	65
Sales to Power Market	34.53	40.17	46.16	47.06	57.27	58.65

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Megawatt Hours)

Table 1.09 **Expected Energy Required/Supplied**

	2009	2010	2011	2012	2013	2014
Expected Energy Disposed	13,735,181	14,633,138	13,944,139	13,659,875	13,875,163	13,941,197
Seattle System Load	10,059,811	9,919,004	10,017,261	10,224,190	10,301,595	10,388,707
Energy Sales out of System	0	0	0	0	0	0
Article 49 Sales to PO County	367,729	370,022	370,022	371,036	370,137	370,112
Encroachment on Box Canyon	0	40,166	40,166	40,272	40,166	40,166
Marketing Losses	67,935	76,318	68,512	61,913	62,912	62,838
Entl/Supp Transfer	0	0	0	0	0	0
Sale of Centralia	0	0	0	0	0	0
Sale of CSPE to Calif	0	0	0	0	0	0
Sale of CSPE to Puget	0	0	0	0	0	0
Seasonal Exchange Delivered	390,805	383,561	90,383	90,577	90,528	90,676
Energy Delivered to Redding	878	878	878	878	878	878
Energy Delivered to SMUD	882	882	882	882	882	882
Lucky Peak Exchange Energy Delivered	887	887	887	887	887	887
Interchange Delivered	0	0	0	0	0	0
Sales to Power Market	2,848,901	3,844,065	3,357,794	2,871,887	3,009,824	2,988,697
Expected Energy Generated	5,831,671	6,271,819	6,270,795	6,291,152	6,277,121	6,276,824
Lake Union	0	0	0	0	0	0
Centralia	0	0	0	0	0	0
Ross	602,878	751,587	751,624	754,330	751,850	753,031
Diablo	645,336	736,219	736,892	739,995	736,156	737,371
Gorge	796,215	883,690	884,620	888,209	883,482	885,298
Boundary	3,651,367	3,759,711	3,756,941	3,767,641	3,764,946	3,760,309
CF/NH	83,719	86,783	86,888	87,023	86,858	86,986
South Fork Tolt	52,156	53,829	53,829	53,954	53,829	53,829
Expected Energy Purchased	7,903,510	8,361,320	7,673,345	7,368,725	7,598,043	7,664,374
Bonneville Power Administration	5,442,203	5,639,596	5,400,474	5,023,331	4,949,387	5,002,628
Losses from BPA	0	0	0	0	0	0
Box Canyon	0	0	0	0	0	0
Priest Rapids	33,286	228,414	24,088	24,153	24,102	24,098
High Ross Contract	312,447	310,246	310,450	311,205	310,048	310,017
CSPE	0	0	0	0	0	0
Grand Coulee	254,917	239,763	239,803	240,277	240,134	239,927
Lucky Peak	300,225	292,981	293,048	293,905	293,478	293,189
Rocky Brook	0	0	0	0	0	0
Metro Cogen	0	0	0	0	0	0
UW Cogen	0	0	0	0	0	0
Klamath Falls	0	0	0	0	0	0
SPI Purchase	20,006	26,280	26,280	26,352	26,280	26,280
Combustion Turbine Two	0	0	0	0	0	0
Wind Resources	375,741	402,844	406,399	403,842	402,359	402,507
IRP Resources	8,468	50,633	78,839	79,057	452,087	452,106
Peak Period Energy	0	0	0	0	0	0
Interruptible Energy	0	0	0	0	0	0
Storage Received (Net)	0	0	0	0	0	0
Seasonal Exchange Received	305,021	374,464	128,064	128,811	128,059	128,797
Energy Received from Redding	0	0	0	0	0	0
Energy Received from SMUD	0	0	0	0	0	0
Lucky Peak Exchange Energy Received	0	0	0	0	0	0
Interchange Received	0	0	0	0	0	0
Purchases from Power Market	851,196	796,099	765,900	837,793	772,110	784,824
Energy to/fr Power Market	1,997,705	3,047,966	2,591,894	2,034,094	2,237,715	2,203,872
Check Load/Resource Balance	-1	-1	-1	-2	-1	-1

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.10 **Production**

	2009	2010	2011	2012	2013	2014
Total Production Expense	39,191,581	47,556,838	48,771,995	51,987,129	53,207,724	54,514,261
Centralia Expenses	0	0	0	0	0	0
Centralia Fuel Expenses	0	0	0	0	0	0
Centralia Non-Fuel Expenses	0	0	0	0	0	0
500 Supervision and Engineering	0	0	0	0	0	0
502 Steam Expense	0	0	0	0	0	0
503 Steam from Other Sources	0	0	0	0	0	0
504 Steam Transferred (Credit)	0	0	0	0	0	0
505 Electric Expenses	0	0	0	0	0	0
506 Miscellaneous	0	0	0	0	0	0
507 Rents	0	0	0	0	0	0
510 Supervision and Engineering	0	0	0	0	0	0
511 Structures	0	0	0	0	0	0
512 Boiler Plant	0	0	0	0	0	0
513 Electric Plant	0	0	0	0	0	0
514 Miscellaneous Steam Plant	0	0	0	0	0	0
515 Maintenance Special	0	0	0	0	0	0
516 Maintenance Clearing	0	0	0	0	0	0
Expenses Not Yet Distributed	0	0	0	0	0	0
Hydro Production	20,113,070	27,351,957	28,079,147	30,838,040	31,554,592	32,330,531
535 Supervision and Engineering	0	0	0	0	0	0
537 Hydraulic Costs	0	0	0	0	0	0
538 Electric Costs	0	0	0	0	0	0
539 Miscellaneous	0	0	0	0	0	0
541 Supervision and Engineering	0	0	0	0	0	0
542 Structures	0	0	0	0	0	0
543 Reservoirs, Dams, Waterways	0	0	0	0	0	0
544 Electric Plant	0	0	0	0	0	0
545 Miscellaneous	0	0	0	0	0	0
Amort of Relicensing Mitigation Expenditures	1,355,465	1,433,639	1,516,697	3,632,686	3,698,562	3,771,755
Expenses Not Yet Distributed	18,757,605	25,918,319	26,562,451	27,205,354	27,856,030	28,558,775
Water for Power Expenses	9,575,984	10,469,557	10,729,755	10,949,740	11,212,088	11,492,730
536 Water for Power (excl Encr)	5,490,778	5,155,389	5,283,515	5,371,683	5,500,621	5,637,175
536 Encroachment	0	1,129,295	1,157,361	1,185,373	1,213,723	1,244,343
540 Rents	4,085,205	4,184,874	4,288,879	4,392,684	4,497,743	4,611,211
Other Power Costs	9,502,527	9,735,323	9,963,093	10,199,348	10,441,045	10,691,001
556 System Control and Dispatch	7,303,162	7,481,897	7,655,983	7,837,042	8,022,252	8,213,881
557 Other Energy Costs (excl GGas Mitig)	1,752,620	1,795,513	1,837,291	1,880,741	1,925,188	1,971,176
557 Greenhouse Gas Mitigation	446,745	457,914	469,819	481,565	493,604	505,944
All City Steam	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.11 **Transmission & Wheeling Revenue and Expenses**

	2009	2010	2011	2012	2013	2014
Revenue from Transmission Services	4,493,661	4,579,411	4,693,008	4,806,594	4,921,652	5,045,451
Maple Valley - Sno King Line Lease to BPA	0	0	0	0	0	0
Sno King - Bothell Line Lease to BPA	0	0	0	0	0	0
Wheeling to North Mountain Substation	345,226	329,765	337,746	345,921	354,294	362,869
Other Wheeling Sales	4,148,435	4,249,646	4,355,261	4,460,673	4,567,358	4,682,583
Other Services	0	0	0	0	0	0
Transmission w/o Wheeling	8,951,350	9,205,191	9,415,939	9,626,149	9,841,608	10,061,110
560 Supervision and Engineering	0	0	0	0	0	0
561 Load Dispatching	0	0	0	0	0	0
562 Station Operation (excl amortization)	0	0	0	0	0	0
563 Overhead Lines	0	0	0	0	0	0
564 Underground Lines	0	0	0	0	0	0
566 Miscellaneous	0	0	0	0	0	0
567 Rents	0	0	0	0	0	0
568 Supervision and Engineering	0	0	0	0	0	0
569 Structures	0	0	0	0	0	0
570 Station Equipment	0	0	0	0	0	0
571 Overhead Lines	0	0	0	0	0	0
572 Underground Lines	0	0	0	0	0	0
573 Miscellaneous	0	0	0	0	0	0
Intertie Operation and Maintenance	538,445	588,754	603,008	617,432	632,999	647,287
Amortization of Puget Intertie	0	0	0	0	0	0
Amortization of Puget Stillwater Sub	99,286	99,286	99,286	99,286	99,286	99,286
Expenses Not Yet Distributed	8,313,619	8,517,151	8,713,645	8,909,431	9,109,322	9,314,537
Wheeling Expenses	40,214,695	48,159,603	48,393,192	49,549,674	50,787,422	51,955,441
Centralia	0	0	0	0	0	0
Boundary	18,972,593	20,095,029	20,095,029	20,575,629	21,094,709	21,570,236
South Fork Tolt	401,528	408,444	418,595	428,727	438,980	450,055
New Resources from Capfile	0	0	0	0	0	0
Box Canyon to Seattle	222,552	235,719	235,719	241,356	247,445	253,023
Entl/Supp Capacity	0	0	0	0	0	0
Priest Rapids	1,316,768	1,394,670	1,394,670	1,428,025	1,464,051	1,497,054
CSPE	0	0	0	0	0	0
Grand Coulee (BPA)	1,298,222	1,375,026	1,375,026	1,407,912	1,443,431	1,475,969
Grand Coulee (Local)	150,651	148,078	148,078	148,745	149,420	150,149
Lucky Peak (BPA)	1,854,603	1,964,323	1,964,323	2,011,303	2,062,044	2,108,527
Lucky Peak (Local)	845,549	2,243,103	2,297,394	2,352,339	2,411,684	2,472,525
Rocky Brook (BPA)	0	0	0	0	0	0
Rocky Brook (Local)	0	0	0	0	0	0
Wind Resources	1,817,135	5,959,330	6,107,437	6,255,258	6,404,861	6,566,443
Interchange Energy	0	0	0	0	0	0
PG&E Exchange	0	0	0	0	0	0
NCPA Exchange	667,657	707,156	707,156	724,069	742,336	759,070
BPA Firm Power	12,054,922	12,768,102	12,768,102	13,073,469	13,403,285	13,705,428
BPA Losses	0	0	0	0	0	0
Out of System Sales	0	0	0	0	0	0
Power Market Sales	0	0	0	0	0	0
Power Market Purchases	314,604	322,279	330,289	338,283	346,373	355,112
Other Wheeling Purchases	297,909	538,343	551,373	564,560	578,802	591,850

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.12 **Distribution & Customer Accounting & Administration**

	2009	2010	2011	2012	2013	2014
Distribution Costs	58,167,623	51,617,066	62,371,739	65,366,864	66,930,259	68,618,759
580 Supervision and Engineering	0	0	0	0	0	0
581 Load Dispatching	0	0	0	0	0	0
582 Station Operation	0	0	0	0	0	0
583 Overhead Lines	0	0	0	0	0	0
584 Underground Lines	0	0	0	0	0	0
585 Street Lighting and Signals	0	0	0	0	0	0
586 Meters	0	0	0	0	0	0
587 Customers Installation	0	0	0	0	0	0
588 Miscellaneous	0	0	0	0	0	0
589 Rents	0	0	0	0	0	0
590 Supervision and Engineering	0	0	0	0	0	0
591 Structures	0	0	0	0	0	0
592 Station Equipment	0	0	0	0	0	0
593 Overhead Lines	0	0	0	0	0	0
594 Underground Lines	0	0	0	0	0	0
595 Line Transformers	0	0	0	0	0	0
596 Street Lighting and Signals	0	0	0	0	0	0
597 Meters	0	-23,950,528	-14,794,056	-13,394,083	-13,714,426	-14,060,411
598 Miscellaneous	0	11,259,893	11,259,893	11,259,893	11,529,194	11,820,050
Waiver of Appliance Repair Charge	0	0	0	0	0	0
Waiver of Trouble Call Charge	1,126	1,154	1,184	1,214	1,244	1,275
Expenses Not Yet Distributed	58,166,497	64,306,547	65,904,717	67,499,840	69,114,248	70,857,845
Customer Accounting & Advisory	34,701,094	36,851,696	38,011,354	39,339,969	40,376,043	41,213,579
901 Supervision of Accounting	0	0	0	0	0	0
902 Meter Reading	0	0	0	0	0	0
903 Customer Records	0	0	0	0	0	0
904 Uncollectable Accounts	4,861,039	5,289,865	5,665,984	6,212,573	6,457,069	6,440,278
905 Miscellaneous Accounting	0	0	0	0	0	0
907 Supervision of Assistance	0	0	0	0	0	0
908 Customer Assistance w/o Cons	0	0	0	0	0	0
908 Rate Relief Administraton	464,219	475,585	486,556	497,489	508,651	520,109
910 Miscellaneous Assistance	0	0	0	0	0	0
Expenses Not Yet Distributed	29,375,836	31,086,246	31,858,813	32,629,907	33,410,323	34,253,191
Administration & General	59,616,485	65,274,640	66,941,425	68,580,857	70,232,998	72,048,896
920 Salaries	0	0	0	0	0	0
921 Office Supplies	0	0	0	0	0	0
923 Outside Services	0	0	0	0	0	0
924 Property Insurance	0	0	0	0	0	0
925 Injuries and Damages	0	0	0	0	0	0
926 Unallocated Pensions & Benefits	0	0	0	0	0	0
927 Franchise Requirements	0	0	0	0	0	0
930 Research & Development	0	0	0	0	0	0
930 Miscellaneous excluding R&D	0	0	0	0	0	0
931 Rents	0	0	0	0	0	0
935 Maintenance of General Plant	0	0	0	0	0	0
935 Depreciation of Vehichles and Boats	2,112,060	2,163,750	2,214,095	2,266,457	2,320,020	2,375,439
Expenses Not Yet Distributed	83,896,706	90,149,084	92,394,641	94,636,025	96,903,919	99,356,909
Deferred A & G (Credit)	-26,392,281	-27,038,194	-27,667,311	-28,321,626	-28,990,941	-29,683,452
Percentage of Customer Revenue That is Not Collectable	0.900	0.900	0.900	0.900	0.900	0.900

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.13 **Taxes**

	2009	2010	2011	2012	2013	2014
Taxes	61,997,078	67,525,892	71,512,374	78,073,044	80,685,250	80,795,260
Seattle City Taxes	33,948,560	37,182,253	39,530,127	43,465,800	44,964,968	44,917,829
Business	11,400	11,845	12,319	12,799	13,286	13,791
Occupation	33,937,159	37,170,408	39,517,808	43,453,001	44,951,682	44,904,038
Sales out of System	0	0	0	0	0	0
State Taxes	21,231,504	23,247,993	24,713,478	27,167,156	28,104,582	28,079,868
Business	106,424	110,574	114,997	119,482	124,023	128,735
Public Utility	21,120,052	23,132,193	24,593,047	27,042,028	27,974,699	27,945,050
Other	5,029	5,225	5,434	5,646	5,860	6,083
King County Surface Water Management Fees	144,377	144,377	144,377	144,377	144,377	144,377
Whatcom County Contract Pmts	895,689	916,443	937,679	959,407	981,638	1,004,384
Pend Oreille County Contract Pmts	1,349,192	1,383,783	1,419,592	1,454,340	1,490,142	1,528,537
Lewis County Contract Pmts	0	0	0	0	0	0
Renton Business Tax	89	92	96	100	104	108
Arbitrage Payments	0	0	0	0	0	0
Payments to Concrete School District	114,545	117,482	120,522	123,472	126,511	129,771
Unallocated Unemployment Tax	0	0	0	0	0	0
Unallocated Social Security Tax	0	0	0	0	0	0
Payments to Franchises	4,313,123	4,533,469	4,646,503	4,758,393	4,872,927	4,990,387
Payments to Shoreline	1,500,246	1,650,270	1,688,341	1,726,277	1,765,008	1,804,770
Payments to Burien	744,099	762,702	782,532	802,096	822,148	842,702
Payments to Lake Forest Park	261,122	267,650	274,609	281,474	288,511	295,724
Payments to Tukwilla	1,678,297	1,720,254	1,764,981	1,809,105	1,854,333	1,900,691
Payments to Sea-Tac	129,359	132,593	136,040	139,441	142,927	146,500
Payments on Surcharge	0	0	0	0	0	0
Pct Revenue Deductible from City Tax	2.50	2.50	2.50	2.50	2.50	2.50
Pct Revenue Deductible from State Tax	6.00	6.00	6.00	6.00	6.00	6.00
City Revenue Tax Rate Percent	6	6	6	6	6	6
State Revenue Tax Rate Percent	4	4	4	4	4	4
Revenue Tax Base	580,122,384	635,391,593	675,518,093	742,786,336	768,404,818	767,590,399
Revenue from Energy Sales to Customers	538,044,802	585,237,568	626,728,681	687,028,483	714,046,784	712,307,604
Other Revenue	21,019,774	23,559,782	23,384,905	22,327,868	22,881,787	23,459,303
Contributions in Aid of Construction	21,057,808	26,594,243	25,404,506	33,429,985	31,476,247	31,823,491
Check Revenue Tax Base	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.14 **Other Revenue, Other Income (Expense) and Other Funds Required**

	2009	2010	2011	2012	2013	2014
Other Revenue	21,019,774	23,559,782	23,384,905	22,327,868	22,881,787	23,459,303
Late Payment Fees	3,535,734	3,622,266	3,706,548	3,794,205	3,883,873	3,976,647
Revenue From Damage	1,301,683	1,333,540	1,364,569	1,396,840	1,429,851	1,464,006
Other O&M Revenue	6,986,150	6,619,630	5,374,846	5,501,958	5,631,984	5,766,516
Rental Income	1,230,516	1,260,631	1,289,963	1,320,470	1,351,676	1,383,964
Construction Charges	10,254	10,505	10,750	11,004	11,264	11,533
Transmission Attachments & Cell Sites	1,341,184	1,394,831	1,450,625	1,508,650	1,568,996	1,631,755
Class 1 Pole Attachments	1,333,728	1,366,381	1,397,903	1,429,312	1,461,381	1,494,303
Class 2 Pole Attachments	0	0	0	0	0	0
Account Change Fee	1,439,116	1,448,010	1,455,656	1,492,047	1,529,349	1,567,582
Water Heater Rentals	0	7,027,302	5,823,002	4,326,602	4,430,080	4,541,842
Miscellaneous Rentals	179,031	183,412	187,680	192,119	196,659	201,356
Reconnect Charges	236,948	242,747	248,395	254,269	260,278	266,496
Miscellaneous Income	3,425,430	-949,474	1,074,969	1,100,392	1,126,397	1,153,303
Other Income (Expense), Net	-376,344	-266,502	-272,805	-279,258	-285,863	-292,625
Miscellaneous Other Income(Expense)	-116,000	0	0	0	0	0
Less Payments From Low Income Account	-260,344	-266,502	-272,805	-279,258	-285,863	-292,625
Less Amortization of Georgetown	0	0	0	0	0	0
Fees and Grants Available for Debt Service	952,000	710,000	185,000	0	0	0
Direct Funding for Lighting Design Lab	0	0	0	0	0	0
Operating Grants from Sound Transit	0	0	0	0	0	0
Operating Grants from FEMA	750,000	0	0	0	0	0
Other Operating Fees and Grants	202,000	710,000	185,000	0	0	0
Operating Transfers	0	0	0	0	0	0
Other Funds Required, Net	15,376,551	-784,548	9,488,863	9,759,743	5,642,734	985,938
Plus Add to Materials and Supplies	595,291	621,482	636,182	651,229	666,633	682,401
Plus Add to Low Income Fund	0	0	0	0	0	0
Plus Add to Cash	0	0	0	0	0	0
Plus Add to Accrued Unbilled Revenue	-2,610,638	3,398,827	3,287,884	3,534,938	1,746,550	-332,779
Plus Add to Accounts Receivable	10,391,897	-4,804,857	5,564,798	5,573,576	3,229,551	636,317
Plus Add to Other Assets	0	0	0	0	0	0
Minus Claims Expensed but not Paid	0	0	0	0	0	0
Minus Add to Accts Payable and Other Liab	-7,000,000	0	0	0	0	0
Minus Loan Discounts Expensed	0	0	0	0	0	0

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.15 **Interest Income, Interest Rates, Inflation and Reserve Fund Details**

	2009	2010	2011	2012	2013	2014
Interest Income	4,943,975	4,208,965	7,322,873	8,971,198	9,435,389	11,074,044
Bond Reserve Fund	0	0	0	0	0	0
Low Income Account	0	0	0	0	0	0
Debt Service Pmt Account	0	0	0	0	0	0
Working Capital Account	3,863,427	2,706,459	5,391,614	6,574,946	6,822,927	8,448,135
Miscellaneous Accounts	108,169	114,215	120,589	125,113	129,044	134,815
Suburban Undergrounding	972,380	1,388,291	1,810,670	2,271,138	2,483,419	2,491,093
Conservation Loans	0	0	0	0	0	0
Own AFUDC	0	0	0	0	0	0
Avg Daily Balance in Working Capital Acct	183,710,251	180,430,602	217,250,349	181,831,939	173,135,132	174,513,647
Average Annual Balance	151,140,303	64,068,936	99,843,173	99,802,454	75,000,000	75,000,000
Bubble From 1st-Lien Debt	0	82,777,774	82,777,774	46,322,026	61,316,053	61,548,343
Bubble From 2nd-Lien Debt	0	0	0	0	0	0
Bubble From 3rd-Lien Debt	0	0	0	0	0	0
Bubble From Transfer from MLP Fund	0	0	0	0	0	0
Bubble From Other Sources	32,569,948	33,583,892	34,629,402	35,707,460	36,819,079	37,965,304
Interest Rates (Percent)						
1st-Lien Debt	5.50	4.83	4.98	5.47	5.60	5.77
2nd-Lien Debt	4.00	4.00	4.00	4.00	4.00	4.00
3rd-Lien Debt	5.00	4.33	4.48	4.97	5.10	5.27
Bond Reserve Fund	2.10	1.50	2.48	3.62	3.94	4.84
Low Income Account	2.10	1.50	2.48	3.62	3.94	4.84
Working Capital Account	2.10	1.50	2.48	3.62	3.94	4.84
Month.Day of 1st-Lien Debt	2	2	2	2	2	2
Month.Day of 2nd-Lien Debt	10	10	10	10	10	10
Month.Day of 3nd-Lien Debt	10	10	10	10	10	10
Number of Months to First Coupon Payment	6	11	11	11	6	6
Years Over which Debt Service Payments Spread	25	25	25	25	25	25
Years Delay in Principal Payments	0	1	1	1	0	0
Seattle CPI-W (1982-84=100)	225.184	230.678	236.411	242.133	247.924	254.179
Seattle CPI-W (2007=1)	1.07095	1.09708	1.12434	1.15156	1.17910	1.20884
Rate of Inflation (Percent)	2.500	2.440	2.485	2.420	2.392	2.523
Bond Reserve	106,964,864	111,147,883	121,238,743	123,304,025	128,057,107	132,697,765
ML&P Fund	0	0	0	0	0	0
Surety Bonds	106,964,864	111,147,884	121,238,744	123,304,025	128,057,107	132,697,766
Additions to Bond Reserve	0	4,183,020	10,090,860	2,065,282	4,753,082	4,640,658
Additions to ML&P Fund	0	0	0	0	0	0
Additions to Surety Bonds	0	4,183,020	10,090,860	2,065,282	4,753,082	4,640,658
Surety Bond Premium	0	96,209	232,090	47,501	109,321	106,735
Surety Bond Premium Rate (Percent)	2.3	2.3	2.3	2.3	2.3	2.3

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.16 **Probability Distribution of Cash Deviations - Part One**

	2009	2010	2011	2012	2013	2014
Deviations at 0% Probability of Exceedence	40,145,524	386,176,399	242,794,838	297,156,880	394,369,345	380,101,454
1%	22,029,240	177,073,061	180,558,810	154,359,345	179,757,716	200,899,336
2%	20,058,403	151,984,751	153,036,588	134,904,227	149,487,800	171,570,672
3%	18,155,473	132,287,258	136,497,105	121,344,899	135,488,179	146,417,816
4%	16,320,669	117,427,189	121,718,014	105,805,365	120,534,801	132,092,102
5%	14,911,457	107,618,072	114,846,510	97,823,792	114,195,847	121,953,386
6%	13,915,056	100,455,878	107,746,547	88,549,050	106,275,491	114,033,433
7%	13,018,493	92,488,480	98,693,258	82,579,115	101,346,667	101,468,623
8%	12,488,491	83,745,458	90,215,211	77,285,492	94,335,678	97,586,863
9%	11,678,278	80,005,729	83,739,267	72,663,101	88,917,763	90,825,109
Deviations at 10% Probability of Exceedence	11,107,717	73,687,784	79,271,910	69,089,017	84,521,505	85,248,250
11%	10,276,393	69,072,711	75,143,070	66,266,404	78,819,925	80,558,479
12%	9,603,622	64,206,457	71,267,128	62,622,905	75,291,448	75,820,614
13%	9,058,433	60,042,580	67,409,675	58,863,703	70,860,601	72,086,892
14%	8,457,653	55,180,240	63,158,781	55,148,581	68,192,216	67,648,805
15%	8,183,508	52,007,644	59,694,730	51,857,134	65,547,481	64,985,707
16%	7,813,121	47,315,199	55,549,436	49,457,967	62,469,592	62,420,686
17%	7,441,956	44,459,369	52,137,266	46,404,619	58,353,197	58,313,632
18%	7,033,174	41,536,104	49,203,230	43,677,963	53,806,556	55,296,622
19%	6,509,723	38,651,758	45,207,532	41,102,318	51,201,728	52,392,245
Deviations at 20% Probability of Exceedence	6,192,200	36,885,075	41,924,414	38,985,788	49,084,221	48,963,938
21%	5,902,288	33,251,728	38,576,524	36,656,177	46,561,567	47,401,814
22%	5,538,268	30,852,236	36,475,622	35,193,439	44,088,176	44,258,122
23%	5,136,912	28,860,617	33,694,605	33,035,295	41,482,526	40,733,182
24%	4,898,224	26,976,741	31,065,864	31,007,349	38,780,434	38,303,504
25%	4,612,083	25,657,907	28,534,585	28,791,829	36,549,534	35,708,889
26%	4,412,353	24,235,124	25,885,178	26,942,478	34,952,183	34,429,002
27%	4,138,697	22,229,584	24,205,359	25,341,000	31,585,067	31,952,036
28%	3,838,080	20,708,908	22,257,263	23,719,649	30,014,865	30,179,871
29%	3,568,698	17,404,781	20,068,649	21,864,103	27,911,088	28,040,235
Deviations at 30% Probability of Exceedence	3,302,477	15,293,153	18,415,259	20,220,746	24,921,150	25,293,582
31%	3,051,884	14,240,573	17,461,194	19,164,807	22,867,447	23,158,619
32%	2,781,255	12,901,227	15,820,576	17,615,880	21,123,931	21,972,870
33%	2,603,402	11,615,745	14,339,526	16,281,903	18,955,033	20,091,652
34%	2,405,828	10,081,307	12,943,807	14,374,643	17,213,776	18,445,093
35%	2,224,404	8,381,857	11,129,954	13,035,417	15,992,795	16,871,531
36%	2,039,184	7,446,926	9,460,875	12,055,843	13,902,668	15,009,122
37%	1,854,755	6,606,952	6,991,908	10,562,216	12,819,568	13,331,130
38%	1,660,201	5,578,565	5,204,907	9,264,200	11,739,581	11,426,455
39%	1,464,508	4,237,385	3,741,799	7,886,398	10,237,814	9,898,188
Deviations at 40% Probability of Exceedence	1,192,920	3,014,144	2,527,269	6,959,583	8,724,730	7,955,903
41%	953,203	963,015	1,103,302	5,603,248	6,953,243	6,397,311
42%	758,812	-346,775	-131,627	4,286,308	4,844,287	4,963,607
43%	548,662	-1,483,983	-1,316,673	2,015,523	3,561,702	3,604,686
44%	315,630	-2,995,028	-2,105,203	134,140	2,641,421	1,762,627
45%	108,136	-4,210,692	-3,501,543	-676,814	1,142,530	319,082
46%	-95,346	-5,202,066	-4,477,263	-1,950,058	-38,595	-1,304,467
47%	-298,047	-6,527,945	-5,767,521	-3,585,160	-1,674,058	-2,627,573
48%	-561,636	-7,766,285	-6,968,706	-4,795,115	-3,232,326	-3,993,517
49%	-818,807	-8,880,813	-8,638,836	-5,365,568	-4,321,014	-5,452,179
Deviations at 50% Probability of Exceedence	-1,098,880	-9,944,094	-9,726,771	-6,397,669	-5,742,310	-7,107,110

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars)

Table 1.17 **Probability Distribution of Cash Deviations - Part Two**

	2009	2010	2011	2012	2013	2014
Deviations at 50% Probability of Exceedence	-1,098,880	-9,944,094	-9,726,771	-6,397,669	-5,742,310	-7,107,110
51%	-1,259,436	-11,430,946	-10,832,448	-7,533,544	-6,587,003	-8,592,252
52%	-1,412,882	-12,433,696	-11,835,930	-8,536,925	-7,661,711	-10,169,711
53%	-1,645,076	-13,432,136	-12,993,612	-9,844,244	-9,496,149	-11,732,363
54%	-1,916,308	-14,720,277	-13,912,082	-11,062,997	-11,428,412	-12,979,207
55%	-2,093,127	-16,153,368	-14,830,021	-12,733,974	-12,750,246	-14,248,376
56%	-2,214,304	-17,428,662	-15,953,735	-13,758,623	-13,772,849	-15,773,975
57%	-2,418,229	-18,496,530	-17,272,135	-14,672,043	-15,635,378	-17,694,128
58%	-2,620,894	-19,431,026	-18,292,911	-15,730,526	-16,710,307	-19,169,771
59%	-2,773,842	-20,657,075	-19,616,902	-16,904,465	-18,494,594	-21,475,058
Deviations at 60% Probability of Exceedence	-2,960,411	-21,537,007	-21,080,893	-18,284,021	-20,330,476	-23,028,587
61%	-3,099,454	-22,635,066	-22,113,683	-19,400,386	-21,369,303	-23,970,518
62%	-3,258,741	-23,723,003	-23,031,765	-20,157,593	-22,442,488	-26,049,432
63%	-3,429,761	-24,662,541	-24,280,438	-21,041,036	-23,878,108	-27,299,734
64%	-3,624,638	-25,785,718	-25,257,258	-22,093,003	-25,082,772	-28,787,672
65%	-3,817,098	-26,413,235	-26,810,915	-23,483,691	-26,180,879	-30,323,277
66%	-3,964,899	-27,239,471	-27,757,830	-24,419,274	-28,059,568	-31,670,197
67%	-4,176,687	-28,237,771	-29,481,545	-25,570,046	-30,115,423	-33,073,416
68%	-4,414,194	-29,503,805	-30,681,918	-26,638,923	-31,830,704	-34,827,377
69%	-4,562,108	-30,552,726	-32,432,064	-27,867,290	-33,938,294	-36,269,964
Deviations at 70% Probability of Exceedence	-4,705,882	-31,795,353	-33,603,216	-28,906,330	-34,858,320	-37,324,566
71%	-4,854,005	-32,491,260	-35,287,513	-30,542,809	-36,870,401	-38,619,517
72%	-5,105,458	-33,865,760	-36,622,084	-31,933,567	-38,513,225	-39,953,541
73%	-5,359,304	-35,123,317	-38,126,588	-34,164,152	-40,321,260	-41,377,659
74%	-5,558,896	-36,331,563	-39,551,475	-35,148,048	-41,617,886	-43,601,174
75%	-5,755,098	-37,607,966	-40,786,129	-36,993,002	-44,126,591	-45,366,077
76%	-5,948,526	-38,680,365	-41,954,519	-38,052,298	-45,801,686	-46,893,463
77%	-6,174,878	-39,586,277	-43,734,841	-39,837,481	-48,613,712	-48,978,328
78%	-6,324,521	-40,537,704	-45,046,810	-40,780,446	-50,426,832	-51,425,317
79%	-6,521,965	-42,009,658	-46,391,119	-42,087,045	-52,744,673	-53,727,869
Deviations at 80% Probability of Exceedence	-6,764,770	-43,621,860	-47,416,230	-43,431,664	-54,830,846	-55,437,405
81%	-6,964,241	-44,643,958	-48,898,507	-44,340,402	-56,694,829	-56,963,900
82%	-7,186,903	-45,803,251	-50,082,509	-45,936,786	-58,992,049	-58,563,234
83%	-7,443,040	-47,348,889	-52,126,627	-47,644,851	-61,402,200	-60,826,656
84%	-7,631,833	-48,388,222	-53,342,241	-49,005,867	-62,767,632	-63,347,916
85%	-7,888,511	-49,720,510	-55,452,762	-50,910,574	-64,690,105	-64,843,157
86%	-8,125,688	-51,054,120	-56,711,863	-53,433,725	-66,908,961	-67,603,041
87%	-8,389,520	-53,094,598	-58,785,500	-55,267,140	-69,178,853	-69,607,619
88%	-8,682,088	-55,301,407	-60,355,259	-57,646,916	-71,329,493	-71,740,026
89%	-8,954,045	-56,997,592	-62,317,720	-59,421,661	-74,203,511	-74,827,487
Deviations at 90% Probability of Exceedence	-9,227,890	-58,723,765	-63,820,607	-61,784,982	-76,385,507	-77,036,421
91%	-9,674,885	-60,864,667	-65,820,188	-63,871,757	-79,105,148	-79,660,302
92%	-10,162,526	-62,986,614	-68,622,430	-66,544,209	-81,395,954	-83,534,316
93%	-10,624,638	-65,507,805	-71,404,787	-69,306,366	-83,404,056	-88,073,663
94%	-11,150,012	-68,503,470	-73,926,021	-73,279,360	-87,398,671	-90,623,519
95%	-11,681,197	-70,426,844	-76,669,217	-76,850,371	-91,942,733	-94,929,539
96%	-12,157,525	-74,514,984	-82,266,963	-80,766,421	-97,818,443	-98,140,919
97%	-12,973,221	-78,386,922	-87,021,406	-85,722,340	-104,727,247	-105,312,869
98%	-13,753,626	-82,474,855	-93,318,082	-91,017,823	-111,401,793	-113,616,120
99%	-14,798,771	-89,780,856	-103,316,884	-98,633,235	-122,486,351	-124,621,854
Deviations at 100% Probability of Exceedence	-18,240,630	-126,228,420	-136,431,418	-133,645,505	-192,035,972	-187,689,905

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(Dollars & $/MWH)
Table 2.01 **Revenue from Energy Sales to Customers**

	2009	2010	2011	2012	2013	2014
Revenue from All Retail Customers	538,044,802	585,237,568	626,728,681	687,028,483	714,046,784	712,307,604
Revenue from Residential Customers	190,662,926	205,642,969	219,234,531	238,960,767	245,808,651	242,578,408
Revenue from Non-Residential Customers	347,381,876	379,594,599	407,494,151	448,067,716	468,238,133	469,729,197
Surcharge Revenue from Residential Customers	0	0	0	0	0	0
Surcharge Revenue from Non-Residential Cust.	0	0	0	0	0	0
Revenue from Distribution Capacity Charge	194,929	199,702	204,309	208,899	213,586	218,398
Revenue from First Hill & U-Dist. Network	0	0	0	0	0	0
Revenue from Green Power Residential	218,031	223,096	228,451	233,584	238,824	244,205
Revenue from Green Power Non-Residential	838,472	858,999	878,816	898,563	918,723	939,420
Revenue from Power Factor Charges	2,549,841	2,612,936	2,679,388	2,745,629	2,812,512	2,880,829
Credits for Transformation	-325,719	-333,658	-341,956	-350,236	-358,604	-367,657
Credits for Interruptibility	0	0	0	0	0	0
Credits for Rate Adjustment	0	0	0	0	0	0
Revenue from MWh, kW and BSC Charges (Doll	534,569,248	581,676,493	623,079,673	683,292,043	710,221,743	708,392,409
Residential Service (Regular)	186,715,119	201,211,616	214,462,193	233,723,396	240,396,976	237,187,306
Residential Service (Assisted)	3,729,776	4,208,257	4,543,887	5,003,787	5,172,851	5,146,897
Small General Service	65,896,009	72,360,127	78,480,817	87,309,422	91,539,266	92,057,216
Medium General Service	125,741,022	137,915,809	148,365,305	163,440,365	171,245,833	172,116,958
Large General Service	82,424,876	89,776,827	96,108,034	105,453,562	110,163,308	110,479,408
High Demand General Service	58,548,536	63,595,715	67,737,801	73,934,066	76,850,256	76,702,816
Street and Flood Lights	11,513,910	12,608,142	13,381,636	14,427,445	14,853,254	14,701,810
Average Rates on MWh, kW and BSC ($/MWh)	56.15	61.96	65.72	70.61	72.84	72.04
Residential Service (Regular)	65.04	71.82	76.47	82.51	85.18	84.31
Residential Service (Assisted)	26.27	29.49	31.68	34.57	35.69	35.32
Small General Service	55.80	61.61	65.63	70.92	73.22	72.47
Medium General Service	52.32	57.74	61.08	65.41	67.53	66.84
Large General Service	52.72	58.21	61.58	65.96	68.11	67.42
High Demand General Service	46.28	51.16	54.10	57.93	59.79	59.18
Street and Flood Lights	121.31	132.84	140.99	151.59	156.49	154.89
Sales to Customers (MWh)	9,520,344	9,387,587	9,480,765	9,677,259	9,750,957	9,833,746
Residential Service (Regular)	2,870,822	2,801,515	2,804,534	2,832,723	2,822,280	2,813,281
Residential Service (Assisted)	141,986	142,711	143,446	144,733	144,941	145,703
Small General Service	1,181,026	1,174,544	1,195,843	1,231,037	1,250,248	1,270,271
Medium General Service	2,403,275	2,388,381	2,429,153	2,498,590	2,535,858	2,574,951
Large General Service	1,563,301	1,542,401	1,560,711	1,598,649	1,617,464	1,638,596
High Demand General Service	1,265,019	1,243,119	1,252,164	1,276,352	1,285,250	1,296,029
Street and Flood Lights	94,915	94,915	94,915	95,175	94,915	94,915

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
(MWH, Number & Dollars)
Table 2.02 **Various Other Customer Revenue Parameters**

	2009	2010	2011	2012	2013	2014
Energy Sales by Type of Customer (MWh)	9,520,344	9,387,587	9,480,765	9,677,259	9,750,957	9,833,746
Residential Class	3,019,827	2,951,132	2,954,883	2,984,414	2,974,155	2,965,902
Commercial Class	5,247,434	5,222,094	5,314,685	5,469,429	5,553,950	5,642,240
Industrial Class	1,253,083	1,214,361	1,211,197	1,223,416	1,222,852	1,225,604
Food	52,811	49,943	48,300	47,226	45,556	43,987
Stone	308,053	304,433	307,693	314,340	317,021	319,894
Metals	479,042	471,050	473,197	480,463	481,364	482,597
Aero	253,705	230,659	221,376	216,756	212,357	210,521
Ship	17,845	17,339	17,228	17,264	17,080	16,903
Steam	0	0	0	0	0	0
Other Industry	141,627	140,937	143,402	147,368	149,473	151,702
Firm Energy Required (MWh)	10,059,811	9,919,004	10,017,261	10,224,190	10,301,595	10,388,707
Sales to Customers	9,520,344	9,387,587	9,480,765	9,677,259	9,750,957	9,833,746
Own Use	32,622	32,622	32,622	32,711	32,622	32,622
Unbilled Lighting Load	0	0	0	0	0	0
Losses	506,845	498,795	503,873	514,219	518,016	522,339
Losses as % of Firm Energy Req.	5	5	5	5	5	5
Meters (number)	388,977	391,215	393,139	395,062	396,993	398,865
Residential	344,854	347,092	349,016	350,939	352,871	354,743
Non-Residential	44,123	44,123	44,123	44,123	44,123	44,123
Low Income Assistance	6,308,716	6,866,668	7,271,974	7,810,069	8,065,311	8,048,294
Rate Discounts	5,546,145	6,086,307	6,474,102	6,993,848	7,230,337	7,194,087
Payments from Low Income Account	260,344	266,502	272,805	279,258	285,863	292,625
Appliance Repair	0	0	0	0	0	0
Trouble Calls	1,126	1,154	1,184	1,214	1,244	1,275
Account Change	36,882	37,121	37,327	38,260	39,217	40,197
Administration	464,219	475,585	486,556	497,489	508,651	520,109

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
Rate Period Energy, Revenues from kWh, kW, BSC, and Percentage Rate Changes

Table 3.02 **Rate Period Energy, Revenues from kWh, kW, BSC, and Percentage Rate Changes**

	2009	2010	2011	2012	2013	2014
Revenue from MWh, kW and BSC Charges (Doll	534,569,248	581,676,493	623,079,673	683,292,043	710,221,743	708,392,409
Residential Service (Regular)	186,715,119	201,211,616	214,462,193	233,723,396	240,396,976	237,187,306
Residential Service (Assisted)	3,729,776	4,208,257	4,543,887	5,003,787	5,172,851	5,146,897
Small General Service	65,896,009	72,360,127	78,480,817	87,309,422	91,539,266	92,057,216
Medium General Service	125,741,022	137,915,809	148,365,305	163,440,365	171,245,833	172,116,958
Large General Service	82,424,876	89,776,827	96,108,034	105,453,562	110,163,308	110,479,408
High Demand General Service	58,548,536	63,595,715	67,737,801	73,934,066	76,850,256	76,702,816
Street and Flood Lights	11,513,910	12,608,142	13,381,636	14,427,445	14,853,254	14,701,810
Sales to Customers (MWh)	9,520,344	9,387,587	9,480,765	9,677,259	9,750,957	9,833,746
Residential Service (Regular)	2,870,822	2,801,515	2,804,534	2,832,723	2,822,280	2,813,281
Residential Service (Assisted)	141,986	142,711	143,446	144,733	144,941	145,703
Small General Service	1,181,026	1,174,544	1,195,843	1,231,037	1,250,248	1,270,271
Medium General Service	2,403,275	2,388,381	2,429,153	2,498,590	2,535,858	2,574,951
Large General Service	1,563,301	1,542,401	1,560,711	1,598,649	1,617,464	1,638,596
High Demand General Service	1,265,019	1,243,119	1,252,164	1,276,352	1,285,250	1,296,029
Street and Flood Lights	94,915	94,915	94,915	95,175	94,915	94,915
Rev. from Prior Rates on curr. MWh (Dollars)	531,679,017	526,903,212	587,041,768	635,519,889	687,976,426	715,689,611
Residential Service (Regular)	184,886,402	182,259,577	201,345,829	216,617,351	232,867,346	239,630,590
Residential Service (Assisted)	4,032,882	3,748,746	4,229,800	4,584,441	5,010,829	5,199,915
Small General Service	66,255,815	65,538,588	73,674,492	80,789,546	88,672,105	93,005,505
Medium General Service	125,595,648	124,972,675	140,273,632	152,609,910	165,882,131	173,889,947
Large General Service	81,852,444	81,359,774	90,866,413	98,465,631	106,712,811	111,617,464
High Demand General Service	57,571,087	57,509,942	64,043,460	69,034,789	74,443,179	77,492,937
Street and Flood Lights	11,484,740	11,513,910	12,608,142	13,418,222	14,388,026	14,853,254
Average Rates on MWh, kW and BSC ($/MWh)	56.15	61.96	65.72	70.61	72.84	72.04
Residential Service (Regular)	65.04	71.82	76.47	82.51	85.18	84.31
Residential Service (Assisted)	26.27	29.49	31.68	34.57	35.69	35.32
Small General Service	55.80	61.61	65.63	70.92	73.22	72.47
Medium General Service	52.32	57.74	61.08	65.41	67.53	66.84
Large General Service	52.72	58.21	61.58	65.96	68.11	67.42
High Demand General Service	46.28	51.16	54.10	57.93	59.79	59.18
Street and Flood Lights	121.31	132.84	140.99	151.59	156.49	154.89
Prior Rates applied to curr. MWh ($/MWh)	55.85	56.13	61.92	65.67	70.55	72.78
Residential Service (Regular)	64.40	65.06	71.79	76.47	82.51	85.18
Residential Service (Assisted)	28.40	26.27	29.49	31.68	34.57	35.69
Small General Service	56.10	55.80	61.61	65.63	70.92	73.22
Medium General Service	52.26	52.33	57.75	61.08	65.41	67.53
Large General Service	52.36	52.75	58.22	61.59	65.98	68.12
High Demand General Service	45.51	46.26	51.15	54.09	57.92	59.79
Street and Flood Lights	121.00	121.31	132.84	140.98	151.59	156.49
Change in Average Rate Period Rates (%)	0.54	10.40	6.14	7.52	3.23	-1.02
Residential Service (Regular)	0.99	10.40	6.51	7.90	3.23	-1.02
Residential Service (Assisted)	-7.52	12.26	7.43	9.15	3.23	-1.02
Small General Service	-0.54	10.41	6.52	8.07	3.23	-1.02
Medium General Service	0.12	10.36	5.77	7.10	3.23	-1.02
Large General Service	0.70	10.35	5.77	7.10	3.23	-1.02
High Demand General Service	1.70	10.58	5.77	7.10	3.23	-1.02
Street and Flood Lights	0.25	9.50	6.13	7.52	3.23	-1.02

2009-2010 Revenue Requirements Analysis
Rate Study 2009_09_09
Values sent to the Gear Box

Table 4.01 **Values sent to the Gear Box**

	2,009	2,010	2,011	2,012	2,013	2,014
Target for Debt Service Coverage Ratio	2.0	1.6	1.7	1.8	1.8	1.8
Additional BPA Cost Passed Through to Custome	8,073,553	2,623,101	5,836,460	0	0	0
Cash from BPA Residential Exchange - Slice	6,945,887	3,807,468	3,807,468	3,807,468	3,807,468	3,807,468
Cash from BPA Residential Exchange - Block	3,968,817	2,175,288	2,175,288	2,175,288	2,175,288	2,175,288
Price of Natural Gas (2008 $/MMBTU)	3.41	5.09	5.87	6.00	7.00	7.00
Price of Natural Gas (Actual $/MMBTU)	3.50	5.34	6.31	6.61	7.90	8.10
Serrvice Area MWh Energy Used - Jan	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Feb	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Mar	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Apr	0	0	0	0	0	0
Serrvice Area MWh Energy Used - May	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Jun	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Jul	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Aug	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Sep	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Oct	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Nov	0	0	0	0	0	0
Serrvice Area MWh Energy Used - Dec	0	0	0	0	0	0
For Fiscal-Year Sarting in Oct. of Year Shown						
Additional BPA Cost Passed on to Customers	0	0	0	0	0	0
BPA Pass-Through Revenue (= Cost * 1.1095)	0	0	0	0	0	0
Service Area MWh Energy Used (from BPA Shee	0	0	0	0	0	0
Service Area MWh Energy Used (from WRF Mo	0	0	0	0	0	0
Exact Calculation of Pass Through Rate ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Actual (Rounded) Pass Through Rate ($/MWh)	0.00	0.00	0.00	0.00	0.00	0.00
Percent Change in Cost - BLock	0.00	0.00	0.00	0.00	0.00	0.00
Percent Change in Cost - SLice	0.00	0.00	0.00	0.00	0.00	0.00
Checks						
Check Calendar Year Energy (WRF minus drev)	-9,520,344	-9,387,587	-9,480,765	-9,677,259	-9,750,957	-9,833,746
Check Fiscal-Year Energy (BPA - WRF	0	0	0	0	0	0

Appendix 3 - Review of Seattle City Light's Financial Policies

September 2009

I. Introduction

City Light's financial policies are designed to ensure uninterrupted access to the bond markets, allocate capital costs over time, promote long-term rate stability for customers and maintain long-term operational and fiscal health for the Utility. Targeting all these objectives helps the Utility to provide high quality service at the lowest possible cost to its customers in the long run.

To satisfy its existing financial policies in the near future, City Light must either significantly increase customer rates during an economically sensitive time or reduce programs and services to unacceptable levels. Thus, City Light considers it appropriate to re-evaluate its financial policies so that it can minimize rate impacts to customers and continue providing quality services. In this review, City Light aims to achieve these objectives by modifying the existing financial policies. The following recommendations are made:

1. In combination with an automatic rate adjustment mechanism that would stabilize the Utility's revenue from surplus energy sales, reduce the debt service coverage target for rate setting from the current 2.0 to 1.6 in 2010, 1.7 in 2011, and 1.8 in 2012 and thereafter.
2. Implement an automatic rate adjustment on a quarterly basis that would increase or decrease retail rates depending on whether net wholesale revenue was higher or lower than planned for the previous quarter in the forecast approved by the Council.
3. Drop the current policy of setting rates to assure 95% confidence that there will be at least $1 of revenue available to fund capital requirements in each year, taking into consideration the variability in cash flows resulting from uncertainty in hydro conditions, market prices and system load.
4. Delay achievement of a 60% debt to capitalization ratio from 2010 to 2012.

In this paper City Light presents an overview of the history of financial policies used in rate setting, its current financial policies, and a discussion of how they are used in the rate setting process today. Next, the performance of some of the financial policies is discussed under the current financial environment. Finally, City Light's proposals to amend the current policies to help mitigate rate increases in the coming years, while providing revenue certainty for the Utility to meet its debt service obligations and carry out its planned programs, are discussed.

II. Historical Background

Since 1977 City Light has set electric rates in compliance with specific financial policies adopted by the City Council. The following resolutions preceded Resolutions 30761 of 2005 and 30933 of 2006, which contain the current policies discussed in the next section.

Resolution 25469 of March 1977:

- Debt service coverage provided by current revenues should be 2.0 and should never fall below 1.5.

- Fifty percent of general CIP should be financed with current revenue, though financing of major new CIP projects will be determined by the Mayor and City Council on a case-by-case basis.

Resolution 26849 of March 1983:

- Annual net revenue available for debt service should be at least 2.0 times current annual debt service payments.
- Fifty percent of general CIP should be financed with current revenue, though financing of major new CIP projects will be determined by the Mayor and City Council on a case-by-case basis.
- Revenues must be sufficient to provide an 80% level of confidence that the Department's net earnings will be positive each year.

Resolution 28085 of October 1989:

- Rates should be set to provide for 1.8 debt service coverage on a planning basis.
- Rates should be set to ensure that, with a high degree of confidence, the Department will make a positive cash contribution to its capital improvement program each year.
- Rates should normally be set to achieve positive net income on a planning basis.

Resolution 30428 of December 2001:

- Net revenue available to fund capital requirements in each calendar year should be positive with a probability of at least 95%, taking into account the variability of cash flows resulting from the uncertainty of water conditions, market prices and system load.
- A Contingency Reserve account of $25 million is established. It is to be funded by adding $12.5 million each year, for two years, to the rates that would accomplish the first goal, described above. This period of funding would not commence until City Light had paid off certain short-term obligations and its month-end operating cash balance had reached $30 million, as described below. Funds in the account could be used to cover current obligations in any year in which the amount of net revenue available to fund capital requirements was not positive (no ordinance required).
- In its rate proposals, City Light should target a minimum month-end operating cash balance of $30 million, an amount that was equal to approximately three months of non-power operating expenses.
- Financial policies should be reviewed no later than the second quarter of 2006, and should also be reviewed if there was a significant change in City Light's resource portfolio or if the utility's financial performance deviated significantly from the forecasts underlying the development of the policies in the resolution.

III. Current Rate Setting Financial Policies

The existing financial policies were established in City Council Resolution 30761, adopted May 2, 2005. These policies were re-affirmed in Council Resolution 30933 adopted November 20, 2006, with a change to the requirement for use of the contingency reserve fund.

1. Expected Debt Service Coverage of 2.0

Retail rates should be set so that the expected debt service coverage on first and second lien debt shall achieve 2.0 coverage. A value of 2.0 was selected because, given the volatility in wholesale revenue, it provides a high level of probability that City Light will meet its minimum debt service coverage commitments. By setting rates to achieve at least 2.0 coverage, City Light provides a high level of certainty to the financial community that the Utility will have ample revenue to cover its debt service payments, which helps City Light to maintain its access to low cost financing. A 2.0 coverage was also selected because it provides for a gradual decrease in the debt to capitalization ratio. This has enabled the utility to decrease its debt to capitalization ratio from above 80% for the 2001-2004 period to the low 60% range presently.

2. 95% Confidence of Revenue Available for Capital Requirements

Retail rates should be set so that there is 95% confidence that there will be at least $1 of revenue available to fund capital requirements in each year, taking into consideration the variability in cash flows resulting from uncertainty in hydro conditions, market prices and system load. This policy greatly increases the certainty that SCL will not have to borrow money to cover its operating expenses in a given year. The specific metric of 95% was sized so that, along with the $25M contingency reserve, there would be 99% confidence that the Utility would not have to borrow to pay for its annual operations. The additional retail revenue required to ensure this policy is met is determined from a probabilistic forecast of wholesale and retail revenue given the uncertainty in the factors listed above.

3. $25 Million Contingency Reserve Fund

City Light is required to hold $25 million in a contingency reserve fund. According to Resolution 30761 of 2005, funds from the contingency reserve were to be used to pay for extraordinary costs of operating the electrical system and could only be released with a Council ordinance. However, Resolution 30933 of 2006 allows them to be used to “cover current obligations in any year in which the amount of net revenue available to fund capital requirements is not positive.” It does not specify that an ordinance is required to use these funds.

Both resolutions say that if funds are withdrawn, they must be replenished within two years. As stated above, a fund size of $25 million was chosen so that along with the 95% confidence policy there would be a 99% probability that SCL would not have to borrow to pay for its annual operations.

4. $30 Million Minimum Operating Cash Balance

City Light is required to maintain sufficient operating cash balances in the Light Fund to absorb fluctuations in its operating cash flow. A minimum month-end balance of $30 million, which is meant to cover approximately three months of non-power operating expenses, is to be targeted when setting rates. In most circumstances, this minimum balance applies to the timing of future bond issues. However, if a policy decision or other circumstances delay the size or timing of future bonds during the rate setting process, City Light may have to increase rates above the constraints of other financial polices to ensure that it will have the minimum amount of operating cash.

5. Target a Debt to Capitalization Ratio of 60% by 2010

This policy provides that City Light will set rates to target a debt to capitalization ratio of 60% by the end of 2010. The debt-to-capitalization ratio is the total amount of debt outstanding divided by the sum of accumulated equity and debt outstanding. This policy was designed to help the City Light gradually bring down its debt to equity position after taking on a substantial amount of debt resulting from the 2001 energy crisis, when debt to capitalization exceeded 80%. A high debt level reduces the financial flexibility of the utility, and would make it difficult to take on additional debt in the event of extraordinary circumstances. The existing financial policy resolution does not specify a lower target after 2010.

IV. How the Financial Policies are Used in a Rate Setting Process

Revenue requirements are sized so that both 2.0 debt service coverage and the 95% confidence policies are met (one of these is the "binding constraint"). The other financial policies indirectly impact the revenue requirements. The minimum cash balance ($30 million) influences the timing and potentially the size of future debt issues, which will impact the amount of debt service that needs to be covered in the future. The target debt to capitalization ratio is not binding but can be influenced by adjusting the two binding constraints. Setting the percentage of confidence of revenue available for debt service or the debt service coverage policies at a higher level would lower the debt to capitalization ratio relative to its current trajectory.

It is important to note that the financial policies have little impact on the amount the Utility is going to collect from customers over a specified long period of time but, instead, they impact when collections will take place over that time frame. In the short run, the adopted budget dictates the amount of expenses net of outside revenue that customers will be responsible to cover. Since it is a fundamental policy that all planned <u>operating expenses</u> be covered with current year operating revenue, the financial policies essentially determine how much of the <u>capital program</u> will be financed with current year revenue and how much will be financed with bonds. Over the long run, the only difference between the amounts collected from customers under different financial policies will be a result of the financing cost of issuing debt (including interest costs and bond issuance costs).

V. Current Financial Environment

2009 has been a challenging year financially for City Light. 2009 debt service coverage is projected to be about 1.3 and there is only a low probability that SCL will have positive cash from operations, even as the Utility is making significant cuts to its operating expenses. There are two main reasons why City Light is in this current financial situation. First, wholesale revenue is projected to be around $70 million below what was forecasted when the 2009 budget was adopted. Second, there was no rate increase authorized in conjunction with the adopted 2009 budget, even though at the time the financial policies were shown as not being met (i.e., 2009 debt service coverage was expected to be 1.73). If the 2.0 financial policy had been maintained in 2009, SCL would have increased rates by around 7% and would have been able to absorb the $70 million shortfall in wholesale revenue, as debt service coverage would have most likely only dropped to 1.5. The Utility also would not have had to make sudden disruptive cuts in its programs and service levels. During 2009, management identified the need for these reductions in programs and service levels to avoid running out of cash and to make sure it would have sufficient revenue to pay its debt service.

City Light's budgeted operating expenses and their associated contribution to the revenue requirements have increased substantially in the past years. The three main reasons for the increase are: (1) new programs have been adopted that increase service levels, enhance employee safety and aim to reduce future expenditures; (2) the costs of continuing core business processes have gone up, which the Utility has had little control over; and (3) some discretionary spending has increased that the Utility has justified and City Council has adopted.[10] All increased operating expenses have been put through regulatory scrutiny and have been approved as necessary expenditures. City Light's budget does not contain any substantial level of discretionary funding that can be scaled back in a year of wholesale revenue shortfalls without directly impacting customer service, reliability or other essential aspects of providing utility services. This points to the need for an explicit linkage between the budgetary process and the rate setting process. The need to address this issue has been endorsed by the City Light Advisory Committee.

VI. SCL Proposed Changes

Table 1 below shows City Light's proposed changes to its financial policies.

Table 1. Summary of City Light Proposed Changes in Financial Policies

Financial Policy	Current	SCL Proposed
Target Debt Service Coverage	2.0 in all years	1.6, 1.7 and 1.8, respectively, in 2010, 2011 and 2012
PRAM*	No	Yes
Cash Confidence	95%	na
Debt to Capitalization Ratio	60% by 2010	60% by 2012
Coordinate the Budget and Rate Setting Processes	No	Method to be Determined

* PRAM = Power Revenue Adjustment Mechanism, described below.

Reduce Targeted Debt Service Coverage

SCL has proposed a number of reductions from the 2010 endorsed budget in order to mitigate the size of the retail rate increase that would be necessary to achieve revenue consistent with the existing financial policies. However, even with these cuts, City Light would need roughly a 21% increase in retail rates to satisfy the current financial policy of 2.0 coverage in 2010. This is viewed as too large an increase for its customers to accept at this time, given difficult economic circumstances. As a result, City Light is proposing that customer rates gradually increase over time to provide sufficient revenue for debt service coverage of 1.6, 1.7 and 1.8, respectively, in 2010, 2011 and 2012, with 1.8 continuing as the target in subsequent years. As a result of this and other changes, the rate increase for 2010 could be reduced to approximately 9%, with subsequent single-digit increases in both 2011 and 2012. This would comply with the principle of gradualism, which is one of the Council approved policies upon which City Light rates are to

[10] A more detailed explanation will be included in City Light's revenue requirements proposal.

be established. Over this period, City Light would be on a path to sustainable and strong financial performance.

Adopt a Power Revenue Adjustment Mechanism ("PRAM")
While revising the targeted debt service coverage will put downward pressure on rates, it will not adequately protect the Utility from volatility in wholesale revenue without other policies in place. This would be unacceptable from the standpoint of ensuring sufficient funds to continue stable operations, as well as the nearly inevitable downgrade in City Light's current credit ratings (AA- Standard and Poors/AA2 Moody's) that would result. It is for this reason that City Light is proposing an automatic mechanism to adjust rates in the event of significant volatility in its wholesale revenues.

The proposed PRAM would provide a quarterly credit to customer bills when wholesale revenue is more than planned and place an additional quarterly charge on retail energy sales when wholesale revenue is below planned levels. If net wholesale revenue came in close to planned levels, no change to retail rates would occur; thus, the expected value of the PRAM in any given year would be zero.

The PRAM is a mechanism that allows expected rates to be lower than they would otherwise be under the current financial policies. Without the PRAM, City light would have to either: (1) increase base rates significantly more than what is being proposed; (2) reduce programs and customer services to unacceptable levels; or (3) take on imprudent financial risk. The Utility and its customers can avoid the extremes of any of the above options by adopting a PRAM, which will allow the Utility greater revenue certainty, and keep the expected rates to its customers low.

The PRAM would to some extent decrease rate stability, which is one of the principles of City Light's rate setting. That is, the PRAM will transfer a portion of the volatility of wholesale revenue into retail rates; this is mitigated, however, by having a maximum flow through amount and a band of fluctuation within which no rate change would occur. The volatility in rates that customers will experience will be offset by the benefit of lower rates in the near term. By adopting a less restrictive debt service coverage policy along with the PRAM, customer base rates will be much lower than they would be without the PRAM and a more restrictive financial policy. In other words, adopting a PRAM reduces the expected energy costs to customers but allows the actual rates to fluctuate up and down (subject to the proposed limitation of a one cent increase or decrease in rates per kWh). Unless customers value rate certainty to a higher degree than lower near term rates, they will be better off with the PRAM than they are with rates set under the current financial policies.

Remove the Cash Confidence Constraint
The existing policies include the requirement that that retail rates should be set so that there is 95% confidence that there will be at least $1 of revenue available to fund capital requirements in each year, taking into consideration the variability in cash flows resulting from uncertainty in hydro conditions, market prices and system load. SCL's proposed PRAM will provide sufficient confidence that the Utility will have positive cash from operations available to put towards its capital improvement program, so this constraint would no longer be necessary if the PRAM proposal is adopted. However, if the PRAM is modified to provide less assurance than the

proposal that City Light has put forward, it may be important to retain some comparable cash confidence constraint.

Delay the 60% Debt to Capitalization Ratio Target to 2012

In general, there is no optimal debt to capitalization ratio applicable to all utilities. As a municipality, City Light has a tax advantage, providing it access to a lower cost of capital than most private utilities and customers. Taking advantage of this low cost financing enables customers to benefit, as they usually have a higher discount rate than City Light's cost of capital. However, a lower debt to capitalization ratio would better position the Utility to borrow large amounts of money should another crisis emerge or if the Capital Improvement Program is suddenly accelerated. City Light's financial advisors suggest that long-term debt to capitalization should be somewhere in the 50%-60% range. Given that City Light expects to need to borrow more in the next couple of years than it would if retail rates were higher, the proposed change would delay meeting the 60% target by two years.

Summary of the Impacts of the Proposed Changes

Table 2 below compares City Light's proposed changes to its financial policies with the existing policies. Specifically, the table compares the average system rate, debt to capitalization ratio and the 10-year present value (PV) of the amount collected from customers for each policy option.[11] Below are some general results that can be expected if SCL were to change its financial policies as proposed.

- In the near term, the expected average system rate would be significantly reduced.
- The debt to capitalization ratio would be reduced more slowly, but still trend downward, reaching 51% by 2019 with the proposed changes, versus 44% by 2019 with the existing policies.
- Customers would benefit from lower expected rates over the 10-year period.

Therefore, all other things being equal, when the Utility has lower rates and borrows more to finance its capital programs, the Utility takes on more debt and the current customers benefit in the near term. However, in the longer term, the Utility has more debt that customers will eventually have to pay off.

[11] It should be noted that the 10-year PV is not a long term comprehensive indicator of customer welfare. Its purpose is to show the near term benefits to customers when the Utility borrows more to finance its capital program.

Table 2. Summary of Impacts of City Light's Proposed Financial Policies (Nominal Dollars)

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
SCL Proposed Financial Policies										
Debt Service Coverage	1.60	1.70	1.80	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Average System Rate ($/MWh)	62.61	66.40	71.33	73.58	72.77	78.09	79.98	82.44	86.66	88.62
Debt to Capitalization Ratio	62%	62%	60%	58%	57%	55%	54%	53%	52%	51%
Retail Revenue* ($m)	588	630	690	718	716	773	801	831	881	909
10 Year NPV at 5% ($m)	5,712									
10 Year NPV at 10% ($m)	4,466									
Existing Financial Policies										
Debt Service Coverage	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00	2.00
Average System Rate ($/MWh)	69.37	71.55	75.01	75.38	74.23	79.28	80.89	83.05	87.06	88.74
Debt to Capitalization Ratio	61%	59%	55%	53%	51%	49%	48%	47%	45%	44%
Retail Revenue* ($m)	651	678	726	735	730	785	810	837	885	910
10 Year NPV at 5% ($m)	5,896									
10 Year NPV at 10% ($m)	4,628									
Percent Reduction in Expected Rates from SCL Proposed Policy Change	10%	7%	5%	2%	2%	2%	1%	1%	0%	0%

* before rate discounts

Potential Additional or Alternative Financial Stability Tools

An alternative (or possible supplement) to the PRAM could be the establishment of a revenue stability fund. This would be a cash reserve with the sole purpose of covering deviations from planned wholesale revenue. The fund could be established with cash from operations, meaning the Utility would need to borrow more for its capital program during the year(s) when the fund is being created. Establishing a revenue stability fund would have an opportunity cost, as the Utility would have to take on more debt. However, current customers could still benefit from a revenue stability fund if the Utility sufficiently decreased their base rates in the near term. If funds were drawn from the account they could be replenished with cash from operations in the following year(s), which might involve a temporary rate increase.

A revenue stability fund could be used to replace or supplement a PRAM. A combination of a PRAM and a revenue stabilization fund would also work effectively together. The combination of a moderate PRAM and a moderately sized revenue stabilization fund would maintain revenue certainty while: (1) reducing customer rate volatility, as compared to a PRAM that passes through to customers larger deviations; and (2) reducing the opportunity cost to customers, relative to a large revenue stabilization account with no PRAM. However, a revenue stabilization fund is not currently being considered as part of this recommendation because the utility does not have an attractive source of cash to establish such a fund.

It should also be noted that a revenue stability fund would be separate from the existing contingency reserve fund.

VII. Conclusion

City Light is proposing to make amendments to its current financial policies to:

- Better address volatility in its revenue stream, and prevent the need for significant reductions in customer service that such volatility causes.
- Enhance the financial resilience of the Utility, for both current year financial stability as well as longer term financial strength.
- Ensure a financial profile consistent with high bond ratings to ensure continued access to low- cost bond financing necessary to support the Utility's capital improvement program.
- Help mitigate the increase in customer rates over the next several years that would be necessary with a continuation of the existing financial policies.

The main policy change would be lowering the targeted debt service coverage to 1.6, 1.7 and 1.8, respectively, in 2010, 2011, and 2012. In addition, to ensure that the Utility has enough operating revenue during years of low wholesale revenue, City Light is proposing to implement an automatic Power Revenue Adjustment Mechanism that would place a charge on customer energy sales when wholesale revenue is below planned levels and provide a credit to customer bills when it is above. Finally, if the PRAM is adopted, it is proposed that the policy of 95% confidence of positive net revenue to contribute to the capital program be dropped. The Utility views these policy changes as important tools to mitigate rate impacts on customers during the current challenging economic situation.

Appendix 4 – Seattle City Light Power Revenue Adjustment Mechanism

September 2009

Issue

Seattle City Light meets a substantial portion of its annual revenue requirement with wholesale revenues. In fact, apart from BPA, City Light is the largest public power participant in the Northwest power market. Under normal water conditions, City Light will sell in excess of three million megawatt-hours of surplus energy into the market. On an annual basis this sales activity represents over 30% of City Light's total firm system load. These wholesale revenues help offset costs of City Light operations, debt service and taxes that would otherwise be paid through retail rates. However, wholesale revenues are subject to significant volatility due to hydro generation and wholesale power market prices, both of which are largely uncontrollable and very difficult to forecast. For example, City Light estimates 2010 net wholesale revenue can fall between $45 million and $242 million with an expected value of $120 million.[12] Table 1 illustrates the volatility of the recent past.

Table 1. Net Wholesale Revenue ($M)

2003	2004	2005	2006	2007	2008	2009
$113	$114	$87	$140	$137	$134	$69

Prior to the 2000-2001 energy crisis on the West Coast, fluctuations occurred but their magnitude was much smaller because: a) City Light had less surplus power to sell; and b) market prices were more stable. The current volatility in wholesale revenue makes it difficult for the utility to maintain both financial performance and a stable budget when wholesale revenues are significantly less than planned. In years of extremely low wholesale revenue, City Light must cut back on programs and customer service and/or risk not meeting its debt service coverage commitments. Reducing planned capital expenditures provides no benefit to debt service coverage in the current year. Discretionary expenses that can be changed by management decisions total less than $202 million in 2010; this is not large enough offset a downside wholesale revenue scenario without significant adverse effects on current operations.

City Light's budget does not contain any substantial level of discretionary funding that can be scaled back in a year of wholesale revenue shortfalls without directly impacting customer service, reliability or other essential aspects of utility services. This was demonstrated in 2009 as the Utility struggled to continue to provide services that customers depend on in light of significant budget cutbacks. The utility was forced to make significant cuts in programs such as street lighting, conservation and tree-trimming. Managing revenue risks by cutting back

[12] The $45-$242 million range describes the 5th and 95th percentiles, respectively, of City Light's Rate Study dated 9-09-09.

essential services is not acceptable to customers or their elected representatives, and continued exposure of the Utility to this financial volatility is not consistent with the utility's vision of setting the standard of providing the best customer service of comparable utilities in the nation.

Proposal

To mitigate this volatility, City Light is proposing the adoption of a Power Revenue Adjustment Mechanism (PRAM) that will automatically adjust retail rates to offset the amount by which wholesale revenue differs from levels expected at the time retail rates were set. This proposal is similar to mechanisms already in place in other utilities and even in our own utility. Automatic rate adjustments for uncertain and uncontrollable energy costs and revenues are commonly used in utility rate structures (e.g., fuel cost adjustment clauses, see examples in Table 3 at the end of this paper), and City Light already has a similar automatic adjustment mechanism in place to pass BPA power cost increases or decreases on to its customers.

City Light is proposing a PRAM which would have the potential to adjust rates in three-month increments. A PRAM account balance would be used to track the difference between actual wholesale revenue and a wholesale revenue benchmark adopted by Council ordinance. This benchmark ideally would be the same amount as assumed when retail rates and the budget are adopted, though Council will be allowed discretion to set it to other values. At the end of every month, the difference between the actual and expected wholesale revenue would be reflected in the PRAM Balance. This PRAM Balance would be used to adjust rates based on the criteria below.

Key Features

- Customer rate would be reduced when actual net wholesale revenue is above the adopted benchmark and customer rates would be increased when it is below.
- The charge or credit would be adjusted every three months.
- The PRAM balance must exceed a minimum threshold of $10 million before a rate adjustment would be made. There would be a maximum rate change of $0.01/kWh ($10 per MWh).

City Light proposes that retail rates would be adjusted only when the PRAM Balance falls below negative $10 million and or rises above $10 million. If the PRAM Balance is within this 'deadband', no rate adjustment would be implemented and the PRAM Balance would roll to the next period. Every three months, the entire balance of the account (assuming it exceeds plus or minus $10 million) would then be disbursed to or collected from customers by lowering or raising retail energy rates during the associated three-month adjustment period[13].

A maximum PRAM rate adjustment amount of $0.01/kWh ($10/MWh) would protect customers from extremely large swings in their rates. A $0.01/kWh ($10/MWh) increase or decrease from

[13] A one month administration lag would be needed to calculate and implement the charge or credit. The resulting credit or charge would be provided to billing staff to be placed on all retail sales starting the following month and it would remain in place for three months. For example, the deviations for January through March (first quarter) would be collected or disbursed through retail bills in May through July (first adjustment period).

current rates for the average residential customer, who consumes around 710 kWh per month (or 0.71 MWh per month), would produce a maximum monthly bill change of around $7.10. City Light proposes that any funds in the PRAM Balance not able to be disbursed or collected in one adjustment period because of the maximum adjustment limit be rolled over and disbursed or collected in following periods.

Figure 1 below is an example of how the proposed PRAM would operate under high and low wholesale revenues for a three-month period.

Figure 1

City Light Proposed PRAM

• When actual Wholesale Revenue (WR) is above the adopted benchmark, the surplus revenue is distributed to retail customers through a temporary decrease in their retail rates.

• When Wholesale Revenue is below the adopted benchmark, the revenue deficit is collected from retail customers through a temporary increase in their retail rates.

• Adjustments are made every 3 months.

Example: High Wholesale Revenue for 3 month period

Planned WR = $30 million, Actual WR = $45 million (Difference = +$15 million), expected energy sales in following 3 months = 2.2 million MWh

$15 million deviation is greater than the $10 million threshold

Change customer rates for three months by **-$6.82 per MWh** ($15m/2.2m)

Impact on Average Residential Customer = decrease of $4.84 per month (for 3 months)

Example: Low Wholesale Revenue for 3 month period

Planned WR = $30 million, Actual WR = $15 million (Difference = -$15 million), expected energy sales in following 3 months = 2.2 million MWh

$15 million deviation is greater than $10 million threshold

Change customer rates for three months by **+$6.82 per MWh** ($15m/2.2m)

Impact on Average Residential Customer = increase of $4.84 per month (for 3 months)

Estimated PRAM Performance Results

It is useful to look at the full range of potential outcomes when estimating how a PRAM would perform. The impact on customers and the utility resulting from implementing a PRAM can vary significantly, constrained, of course, by the maximum retail rate change permitted. As part of its forecasting and risk management processes, City Light estimated the range of the uncertainty in wholesale revenue by running over 2000 scenarios that take into account volatility in hydro conditions, market prices and retail load. These scenarios of wholesale revenue were used to estimate the performance of a PRAM over a full range of possible outcomes. PRAM rate adjustments as calculated in each scenario provide a basis for the indicators below, which illustrate the operations of the PRAM.

Table 2 contains summary statistics for average annual PRAM rate adjustments and debt service coverage levels. Table 2 only lists the estimated probabilities for rate increases. Figure 4 contains a full estimated distribution of PRAM adjustments.

The data in Table 2 are defined as follows:

- Average Annual (PRAM) Charge
  - The annual (PRAM) charge is the weighted average of each quarterly charge over the full year.
  - The average annual (PRAM) charge is the annual charge averaged over all scenarios. While each quarterly charge will vary, this is the average charge customers would expect to pay in the first year of the PRAM.
- Probability of Average (PRAM) Charge > a stated amount
  - The estimated probability of having an annual (PRAM) charge greater than the stated amount, given City Light's uncertainty in wholesale revenue.
- City Light Revenue Certainty
  - The estimated probability of achieving debt service coverage greater then the stated amount, given the debt service coverage target used to set rates and City Light's uncertain wholesale revenue.
  - The estimated probability of having positive Cash from Operations (CFO)

Table 2

PRAM Performance Summary Table

	No PRAM	PRAM
Customer Rates Impacts*		
Avg Annual Charge ($/MWh)	na	0.5
Probablility of avg charge > $2/MWh	na	43%
Probablility of avg charge > $4/MWh	na	28%
Probablility of avg charge > $6/MWh	na	14%
SCL Revenue Certainty**		
Probability DSC > 1.5	53%	75%
Probability DSC > 1.6	41%	42%
Probability DSC > 1.7	30%	21%
Probability CFO > 0	87%	99%

* $2, $4 and $6 /MWh are respectively 4%, 7%, 11% increases over the average system rate.
**Assumes an expected DSC of 1.6

On the next page, Figure 3 shows the estimated distributions for debt service coverage and Figure 4 shows the distribution of the annual impact for the average residential customer.

Revenue Stability

City Light is projecting three annual rate increases that would target the proposed debt service coverage levels of 1.6, 1.7 and 1.8 in 2010, 2011 and 2012, respectively. This gradual increase will help ease the financial impact on customers. However, if a PRAM or other risk management strategy is not adopted in conjunction with a reduction in debt service coverage, City Light may face a level of financial risk that is incompatible with its current bond ratings. A rating downgrade would reduce City Light's ability to issue bonds at low rates of interest.

Table 2 and Figure 3 both show that the proposed PRAM provides the needed additional revenue stability for City Light. Without a PRAM, City Light would require a larger 2010 rate increase and/or would have to further reduce its programs and customer service levels. Thus, a PRAM is an essential component of City Light's three-year rate proposal, as it mitigates what would otherwise be a more significant increase in base rates while assuring future bond holders that the utility can generate sufficient revenue, with a very high probability to make debt service payments out of current revenue, even in years of low wholesale revenue.

Figure 3

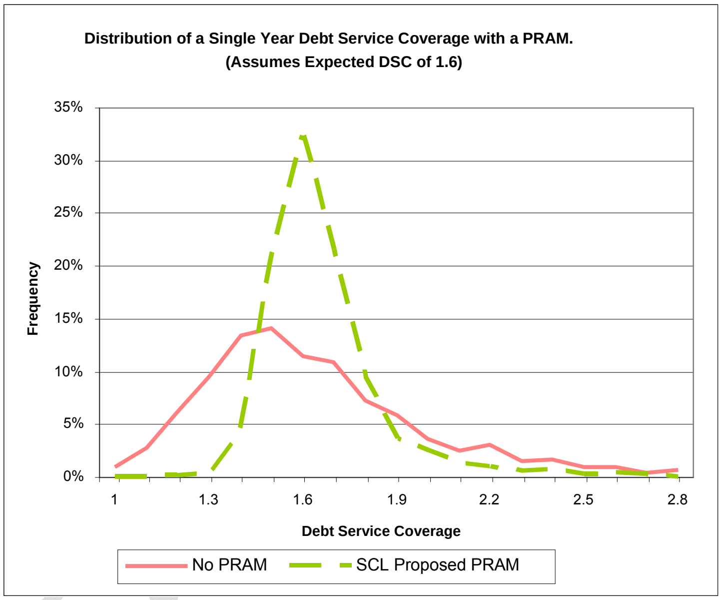
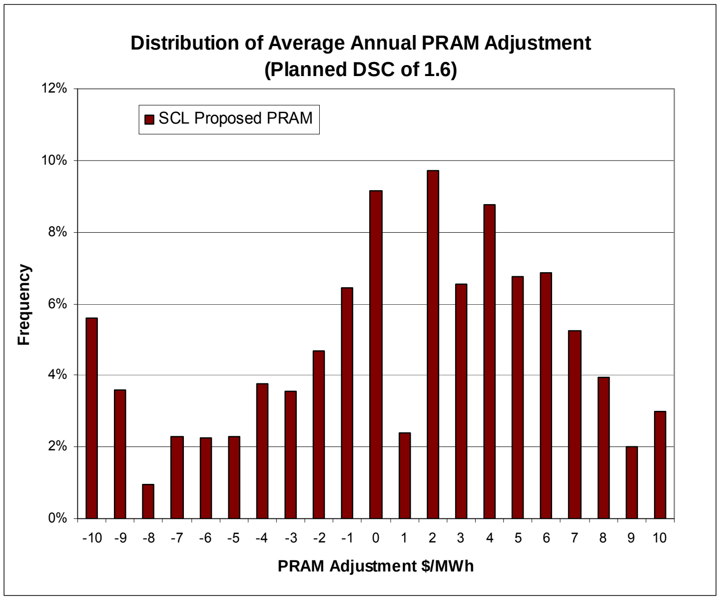


Figure 4



Customer Credits/Charges
Figure 4 shows the estimated distribution of PRAM charges (i.e., rate adjustments). The distribution is not symmetric because the forecast distribution of wholesale revenue is not symmetric, and as a result, the $10 million threshold has disproportionate impacts on credits and charges. City Light estimates that there is a 14% probability that customers would have an annual charge of over $6 per MWh, which is equivalent to a little over $4 a month for an average residential customer.

Financial Policy
If the City Council adopts a PRAM, City Light proposes to modify its financial policies so that its targeted debt service coverage level is reduced to 1.6 for 2010 (and increased to 1.7 and to 1.8 in 2011 and 2012, respectively). City Light believes the establishment of the PRAM will allow the utility to make this financial policy change and still maintain strong credit ratings because a PRAM increases revenue stability. This would provide immediate benefits to ratepayers because a reduction in debt service coverage requirements reduces City Light's revenue requirement and therefore the size of the 2010 rate increase.

Without a PRAM, City Light would need to: (1) increase retail rates significantly more than it is proposing (approximately 21% to meet the 2.0 coverage compared City Light's proposal of 8.8% at 1.6 coverage); (2) make substantial unsustainable program cuts that would jeopardize core customer services; (3) take on imprudent financial risk; or (4) some combination of these unfavorable choices. A reduction in debt service coverage without a PRAM, or other means of managing wholesale revenue risk, would likely lead to a significant credit rating downgrade. The extremes of any of these options are unfavorable and would have both short term and long term repercussions for the utility and its customers. A PRAM could be used as a tool that helps maintain financial stability, ensures continuity of customer service, and maintains the Utility's financial resilience.

City Light recommends that the legislation establishing the new financial policies take the form of a City ordinance rather than a resolution. This would provide additional assurance that, if necessary, action will be taken in 2011, 2012 and beyond to increase rates and achieve these coverage targets. City Light has an accompanying white paper with a broader discussion of financial policies and proposed legislation to implement the recommended changes.

Conclusion
Automatic rate adjustments for uncertain and uncontrollable energy costs and revenues are commonly used in utility rate structures. City Light has an automatic adjustment mechanism in place to pass BPA rate increases or decreases on to its customers. However, wholesale revenue is a substantially larger source of uncertainty in City Light's operating budget than BPA expenses, and the addition of a mechanism to address this volatility is especially warranted to provide the financial stability City Light needs to provide a consistent, high-quality level of service to customers.

Table 3 – Power Cost Adjustment Mechanisms at Other Utilities

Power Cost Adjustment Mechanisms at Other Utilities

Utility	Frequency of true up adjustment	How is it done	Hydro Variation	Major Consideration	Length
Austin	**Annual**	Cents per kWh	No Hydro	Trigger at 10% under collection	Year
Avista-Idaho	Annual	Cents per kWh	Yes	Trigger at 10% under collection	Year
*Avista-WA	Annual	Cents per kWh	Yes	Trigger at 10% under collection (different charge for each class	Year
Puget	When next PCA is Filed	Cents per kWh	Yes	Triggers at $20 Million under collection	is
Baltimore Gas & Electric Co	February-June-October- or more frequently if necessary	Cents per kWh	No Hydro	Cost of energy & transmission related services	
Nashville Electric Service	January-April-July-October	Cents per kWh	No Hydro	Spot market price of coal	
Gulf Power	Annual or next rate case	Cents per kWh	No Hydro	Current month's cost of fuel	Year
*Xcel	When necessary	Cents per kWh	No Hydro	Cost of fuel	3/8 5/8
Portland General Electric	Annual	Cents per kWh	No Hydro	Net cost of fuel, hedges,fuel transportation, power contracts, wholesale sales, & transmissiom/wheeling.	
Duke Energy	Monthly basis	Cents per kWh	No Hydro	Current cost of fuel & purchased power.	
Middle Tennessee Electric	Quarterly	Cents per kWh	No Hydro	Fuel costs-coal-natural gas	
Kodiak Electric	When necessary	Cents per kWh	No Hydro	Current cost of fuel & purchased power.	
CVEC	Monthly basis	Cents per kWh	No Hydro	Actual cost of energy	
Northfork Electric Cooperative	Monthly basis	Cents per kWh	No Hydro	The average cost of power per kWh purchased from suppliers during the previous month.	
Grand River Dam Authority	Monthly basis	Cents per kWh	No Hydro	Some fossil fuel and purchased power.	
Oregon Trail Electric	When necessary	Cents per kWh	No Hydro	When BPA wholesale rates go up or down and future price increases in cogeneration power purchase contracts.	
Idaho Power	Annual	Cents per kWh	No Hydro	Fuel costs and power purchase	
City of Anaheim	Quarterly	Cents per kWh	No Hydro	Costs related to the procurement of generation of energy-power production, purchased power, and any other costs involved in delivering energy.	
Indianapolis Power & Light Co	Quarterly	Cents per kWh	No Hydro	Estimated expense of fuel based on a three month average cost of fossil and nuclear fuels.	
SMUD**	**Proposal - When necessary	Cents per kWh	22 percent	When they are 4% below budget and the seed fund of $30 M falls to $0 M, a surcharge goes into effect. When the seed fund reaches 4% above the $30 M cap, customers receive a deduction in rates.	
LAWP	Quarterly- January 1 April 1-July 1 and October 1.	Cents per kWh	8 percent	The Energy Cost Adjustment (ECA) recovers the cost of fuel, purchased power including renewable resources, demand side management costs ,and revenue losses through application of the Energy Cost Adjustment Factor and other variable operational costs. ECA is adjusted quarterly.	
Grant County PUD	No PCA				
Chelan County PUD	No PCA				

Appendix 5 – Management Decisions Taken to Reduce the Size of the 2010 Rate Increase

Additional Cash from All Other Outside Sources	
Additional Revenue from Renewable Energy Credits (RECs)	500,000
Current Diversion	2,000,000
Pole and Streetlight Damage Claims	200,000
Un-Permitted House Re-wires	56,000
No Longer Allow Flat Rate Billings	50,000
Estimated Bill Charge	50,000
Sale of Surplus Properties	700,700
Monetize excess transmission cpacity	2,000,000
Revenue Offset - Reimbursable Cell Site Work	1,470,602
Total	**7,027,302**
Additions to Cash to Operations (BIPS)	
Streetlight Group Re-Lamping Program	923,080
Asset Management and Work Management Program	2,174,753
Reimbursable Cell Site and Pole Attachment Construction	1,470,602
Self-Build Power Marketing, Risk Management and Settlements	640,577
LED Streelight Conversion Program	26,341
Energy Efficiency Community Block Grant - add to Federal Stimulus	1,050,000
CSED Feeder Maintainance	1,500,000
Security Services	276,450
Crane Safety Program	622,101
Fleet Management Support Staff	181,650
NERC Required Transmission and Distribution Planning	132,290
Baseline Adjustments	499,402
Technical Adjustments - Liability Claims	1,762,647
Total	**11,259,893**
Cuts in Cash to Operations	
Customer Services BU	1,455,054
Energy Delivery BU	8,195,262
Power Supply BU	5,805,210
Conservation/Env Affrs BU	799,103
Financial Services BU	1,576,909
Human Resources BU	620,858
Superintendent's BU	324,776
Benefits Related to Eliminated/Deferred Positions	1,757,803
Cap 2010 COLA at 2.0%	1,612,354
Furloughs	1,803,200
Total	**23,950,528**
Net Changes in Cash to Operations	**(12,690,635)**

Appendix 6 – Components of Increase in Cash to Operations since 2007-2008 Rate Case

2010 data from the budget for 2010 endorsed in 2008. See Chapter 5.

	See Note	2007-2008	2010	Increase
Total Cash to Operations (Millions of Dollars)		**153.4**	**214.4**	**61.0**
Production		**24.0**	**34.5**	**10.5**
Inflation				2.5
Wage Settlements > Inflation				0.6
14 Construction Management Staff	1			1.8
Integrated Resource Plan	2			0.3
Boundary Relicensing	3			1.2
Boundary Sluice Gate Maintenance	4			0.6
Diablo Dredging/Cleaning	5			1.8
Skagit/Boundary-Vessel Maintenance	6			0.4
Skagit Water System Improvement	7			0.2
True-up to Actual Expense				1.1
Transmission		**5.8**	**9.1**	**3.3**
Inflation				0.6
Wage Settlements > Inflation				0.2
True-up to Actual Expense				2.5
Distribution		**41.5**	**64.3**	**22.8**
Inflation				4.4
Wage Settlements > Inflation				1.4
63 Skilled/Line Worker Positions	8			4.6
Apprenticeship Program	9			0.8
Asset Management	10			2.5
Pole Testing/Treatment	11			1.1
Construction and Electrical Materials	12			1.6
Field System & Substation O&M	13			0.5
Fire Resistant Clothing	14			0.3
NERC Regulatory Compliance	15			2.2
Overtime to Repair Outages	16			-1.0
Vegetation Management	17			4.3
True-up to Actual Expense				0.1
Conservation		**2.4**	**8.7**	**6.3**
Inflation				0.3
Wage Settlements > Inflation				0.1
Five Year Plan	18			4.2
Energy Efficiency Fund	19			0.2
True-up to Actual Expense				1.5
Customer Accounting		**26.3**	**31.6**	**5.3**
Inflation				2.8
Wage Settlements > Inflation				0.3
Call Center Payments to SPU	20			1.7
True-up to Actual Expense				0.5
Administration		**53.4**	**66.2**	**12.8**
Inflation				5.7
Wage Settlements > Inflation				1.0
Climate Studies Program	21			0.9
City Cost Allocations	22			1.6
Duwamish Cleanup	23			2.0
Greenhouse Gas Offsets	24			0.9
Low-income Assistance	25			0.2
Rent from City	26			2.6
Risk Management - Annual Audit	27			0.2
Safety Compliance	28			0.4
True-up to Actual Expense				-2.7

Notes

Note	Name	Description
1	14 Construction Management Staff	Construction Management will no longer be performed by Seattle Public Utilities. SCL will require 14 positions to perform this function in-house.
2	Integrated Resource Plan	Additional resources are required to meet the new Washington state law (HB 1010) that requires that City Light file an IRP every two years with the Washington Community, Trade, and Economic Development Department.
3	Boundary Relicensing	SCL must complete studies required for Boundary Dam Relicensing. This facility is the single largest and most cost-effective component of our generation portfolio. The facility operates under a Federal Energy Regulatory Commission license that expires in September 2011.
4	Boundary Sluice Gate Maintenance	One-time maintenance costs for Boundary Sluice Gate Maintenance in 2010. This project will remove the old gate, reconstruct, transport and install a new one. Total cost between $6 to 9 million. Past inspections indicate a 10-year maintenance cycle.
5	Diablo Dredging/Cleaning	Removal of the gravel bar that has partially obstructed the Skagit River will increase power production (and revenue) from the Diablo Powerhouse.
6	Skagit/Boundary-Vessel Maintenance	Skagit and Boundary tugs require servicing so that they can continue to support Skagit and Boundary Hydroelectric operations, comply with US Coast Guard regulations and enhance employee safety.
7	Skagit Water System Improvement	SCL plans to install 59 meters in Diablo and 50 meters in Newhalem in an effort to meet the "Water Use Efficiency" rule (contained in WAC 246-290). This will control leakage rates in both Skagit towns, which are currently in excess of 50%.
8	63 Skilled/Line Worker Positions	SCL needs additional skilled trade staff to avoid overtime and to maintain customer service levels as expected retirements of the aging workforce occur.
9	Apprenticeship Program	Resources are required to provide training to an expanded number of apprentices (about 60 more, or double pre-2009 level). Apprentices are needed to fill skilled electrical positions. The apprenticeship training program helps SCL meet its growing staffing needs due to projected retirements and a very competitive utility job market.

Note	Name	Description
10	Asset Management	Resources are required to implement the Work and Asset Management System and the appropriate asset management practices utility-wide so that SCL can make cost-effective investment decisions when it replaces or maintains its aging infrastructure.
11	Pole Testing/Treatment	The 10-year "test and treat" maintenance cycle will extend the life of wood pole assets and reduce life-cycle costs.
12	Construction and Electrical Materials	Additional funds are needed to purchase needed electrical equipment and materials, as significant price escalation above inflation has been experienced since 2006, despite the slowing economy.
13	Field System & Substation O&M	Fourteen major substations require maintenance that has been largely deferred for a significant number of years. This work is essential to delivery of electricity on the transmission and distribution system.
14	Fire Resistant Clothing	Fire resistant clothing is necessary to comply with National Electric Code enforced through OSHA and Washington State Department of Labor, which will enhance employee safety.
15	NERC Regulatory Compliance	Resources are required to pay increased FERC Water License fees, provide NERC-required validation and modeling of generators, pay increased WECC membership fee and NERC-required background checks by outside vendors. Resources are needed to comply with reliability and regulatory standards and to support the internal oversight group. Resources are required to implement mandatory cyber security standards, which reduce risk of power interruption and risk of non-compliance penalties of up to $1M/day.
16	Overtime to Repair Outages	Additional overtime needed to perform long-deferred maintenance work, and to provide the necessary levels of substation and field system operations; network field operation crews will begin to catch up on network feeder maintenance.
17	Vegetation Management	Additional resources will allow the Department to meet its NERC obligations for vegetation control on the Transmission system and achieve the desired 4-year routine trimming cycle.
18	Five Year Plan	SCL plans to acquire energy conservation to meet its future energy resource needs because it has the least cost, risk and environmental impact of available alternative energy sources.
19	Energy Efficiency Fund	This effort will increase conservation in City buildings by offering loans.

Note	Name	Description
20	Call Center Payments	Seattle Public Utilities operates the customer service call center for SCL. Costs for service are increasing and SCL is required to make payments to SPU.
21	Climate Studies Program	The Climate Research Program looks at potential impacts to SCL's system and adaptive measures that can be taken. SCL has been able to secure an agreement with National Department of Energy labs to use their expertise to help downscale global climate models to our watersheds, helping SCL to assess changes in flows and flooding events and their potential impacts on SCL operations and facilities.
22	City Cost Allocations	The City increased Cost Allocation costs. Non-payment would require reductions in the service levels from other City Departments.
23	Duwamish Cleanup	SCL is required to pay for Duwamish Superfund Cleanup. The budget for environmental cleanup is $2.4M in 2010 and is projected to increase in future years.
24	Greenhouse Gas Offsets	Resources will allow SCL to purchase greenhouse gas offsets. The increase is due to the increased costs of offsets, and the need to purchase more offsets due to the new power contracts City Light is signing. This program is the cornerstone of the Mayor's Climate Action Plan, which calls for City Light to continue to meet the GHG neutrality goal. It is also a requirement in Council Resolution 30144.
25	Low-income Assistance	The Human Services Department - Mayor's Office for Senior Citizens (MOSC) administers the Low-Income Rate Assistance Programs. These programs are the Utility Discount Program and Project Share. In 2009, the Mayor's Office for Senior Citizens implemented an aggressive outreach program to increase customer participation in the Utility Discount Program.
26	Rent and Space Lease	The City has increased rent for the Seattle Municipal Tower. In addition, City Light staff has increased and requires more work space. SCL has leased, built-out and moved employees into new office space.
27	Risk Management - Annual Audit	City Light requires additional resources so that it may comply with Executive and Legislative requirements to receive an objective assessment of Seattle City Light's adherence to the Wholesale Energy Risk Management Policy. An annual independent audit will be conducted.

Note	Name	Description
28	Safety Compliance	SCL needs additional resources to expand its safety training in 22 separate training categories that are required via regulation but are missing from the current training structure. SCL will provide mandatory (on-line) safety training per WAC regulations and hands-on training for field staff in first aid, CPR and blood borne pathogens required by IBEW Local 77 bargaining agreement.

Appendix 7 – Proposed Retail Rate Schedules
Effective January 1, 2010

Seattle City Light Residential Rates
Proposed Rates Effective January 1, 2010

RESIDENTIAL	**JANUARY 1, 2010**			
CITY	**Schedule RSC**		**Schedules REC/RLC**	
Energy Charges	Summer	Winter	Summer	Winter
First Block per kWh	$0.0437	$0.0437	$0.0182	$0.0182
Second Block per kWh	$0.0854	$0.0854	$0.0318	$0.0318
Base Service Chrg per day	$0.0973	$0.0973	$0.0487	$0.0487
SUBURBAN	**Schedule RSS**		**Schedules RES/RLS**	
Energy Charges	Summer	Winter	Summer	Winter
First Block per kWh	$0.0465	$0.0465	$0.0195	$0.0195
Second Block per kWh	$0.0885	$0.0885	$0.0331	$0.0331
Base Service Chrg per day	$0.0973	$0.0973	$0.0487	$0.0487
TUKWILA	**Schedule RST**		**Schedules RET/RLT**	
Energy Charges	Summer	Winter	Summer	Winter
First Block per kWh	$0.0492	$0.0492	$0.0208	$0.0208
Second Block per kWh	$0.0933	$0.0933	$0.0351	$0.0351
Base Service Chrg per day	$0.0973	$0.0973	$0.0487	$0.0487
SHORELINE	**Schedule RSH**		**Schedules REH/RLH**	
Energy Charges	Summer	Winter	Summer	Winter
First Block per kWh	$0.0482	$0.0482	$0.0203	$0.0203
End Block per kWh	$0.0902	$0.0902	$0.0339	$0.0339
Base Service Chrg per day	$0.0973	$0.0973	$0.0487	$0.0487
	North City Undergrounding Charge:		North City Undergrounding Charge:	
	All kWh at $0.0007 per kWh		All kWh at $0.0003 per kWh	
	Aurora 1 Undergrounding Charge:		Aurora 1 Undergrounding Charge:	
	All kWh at $0.0017 per kWh		All kWh at $.0007 per kWh	
BURIEN	**Schedule RSB**		**Schedules REB/RLB**	
Energy Charges	Summer	Winter	Summer	Winter
First Block per kWh	$0.0465	$0.0465	$0.0195	$0.0195
End Block per kWh	$0.0885	$0.0885	$0.0331	$0.0331
Base Service Chrg per day	$0.0973	$0.0973	$0.0487	$0.0487
	1st Ave So. 1 Undergrounding Charge:		1st Ave So. Undergrounding Charge:	
	All kWh at $0.0037 per kWh		All kWh at $0.0015 per kWh	

SMALL GENERAL SERVICE — **JANUARY 1, 2010**

	Schedule SMC Schedule SMD		Schedule SMS
CITY	All year	**SUBURBAN**	All year
Per kWh	$0.0612	Per kWh	$0.0638
Minimum bill per meter per day	$0.23	Minimum bill per meter per day	$0.23

	Schedule SMT		Schedule SMH
TUKWILA	All year	**SHORELINE**	All year
Per kWh	$0.0650	Per kWh	$0.0650
Minimum bill per meter per day	$0.23	Minimum bill per meter per day	$0.23
			North City Undergrounding Charge:
			All kWh at $0.0007 per kWh
			Aurora 1 Undergrounding Charge:
			All kWh at $0.0017 per kWh

	Schedule SMB
BURIEN	All year
Per kWh	$0.0638
Minimum bill per meter per day	$0.23
	1st Ave So. Undergrounding Charge:
	All kWh at $0.0037 per kWh

MEDIUM GENERAL SERVICE — **JANUARY 1, 2010**

	Schedule MDC		Schedule MDD
CITY	All year	**CITY**	All year
Per kWh	$0.0528	Per kWh	$0.0612
Per kW	$1.03	Per kW	$1.59

	Schedule MDS		Schedule MDT
SUBURBAN	All year	**TUKWILA**	All year
Per kWh	$0.0565	Per kWh	$0.0576
Per kW	$1.03	Per kW	$1.03

	Schedule MDH		Schedule MDB
SHORELINE	All year	**BURIEN**	All year
Per kWh	$0.0574	Per kWh	$0.0565
Per kW	$1.03	Per kW	$1.03
	North City Undergrounding Charge:	1st Ave So. Undergrounding Charge:	
	All kWh at $0.0007 per kWh	All kWh at $0.0037 per kWh	

Aurora 1 Undergrounding Charge:

All kWh at $0.0017 per kWh

LARGE GENERAL SERVICE **JANUARY 1, 2010**

	Schedule LGC		Schedule LGD
CITY	All year	**CITY**	All year
All kWh Off-peak at	$0.0417	All kWh Off-peak at	$0.0457
All kWh Peak at	$0.0594	All kWh Peak at	$0.0655
All kW Off-Peak at	$0.21	All kW Off-Peak at	$0.21
All kW Peak at	$0.80	All kW Peak at	$1.68
Minimum bill per meter per day	$27.93	Minimum bill per meter per day	$27.93

	Schedule LGS		
SUBURBAN	All year	**TUKWILA**	All year
All kWh Off-peak at	$0.0449	All kWh Off-peak at	$0.0461
All kWh Peak at	$0.0642	All kWh Peak at	$0.0661
All kW Off-Peak at	$0.21	All kW Off-Peak at	$0.21
All kW Peak at	$0.80	All kW Peak at	$0.80
Minimum bill per meter per day	$27.93	Minimum bill per meter per day	$27.93

	Schedule LGH
SHORELINE	All year
All kWh Off-peak at	$0.0457
All kWh Peak at	$0.0650
All kW Off-Peak at	$0.21
All kW Peak at	$0.80
Minimum bill per meter per day	$27.93

North City Undergrounding Charge:

All kWh at $0.0007 per kWh

Aurora 1 Undergrounding Charge:

All kWh at $0.0017 per kWh

HIGH DEMAND GENERAL SERVICE **JANUARY 1, 2010**

	Schedule HDC		Schedule HDT
CITY	All year	**TUKWILA**	All year
All kWh Off-peak at	$0.0401	All kWh Off-peak at	$0.0413
All kWh Peak at	$0.0569	All kWh Peak at	$0.0588
All kW Off-Peak at	$0.21	All kW Off-Peak at	$0.21
All kW Peak at	$0.80	All kW Peak at	$0.80
Minimum bill per meter per day	$118.82	Minimum bill per meter per day	$118.82

Appendix 8 – Relationships among Cash Flow Table Elements and the Debt Service Coverage Ratio

There are arithmetic relationships among the Department's cash transactions outlined in Table 1 in the Summary chapter. In order to understand the determination of the Department's revenue requirement relative to the other elements of Table 1, it is instructive to examine those relationships explicitly. The first item in Table 1, Retail Revenue before Rate Discounts, is the Department's revenue requirement and is the subject or target of this report. The elements in Table 1 can be grouped into six specific categories (from the top down). It will become clear that the Department's revenue requirement is affected and controlled by some, but not all, of the categories and specific elements in that table. Additionally, it is possible to show the importance of the financial policy's desired debt service coverage in affecting the revenue requirement.

Some symbols will be useful to explain these relationships. Let **Ratio** stand for the debt service coverage ratio indicated by City Light's financial policies. The other categories and symbols for elements in Table 1 are:

(Category 1) Cash from major revenue sources. This includes the Department's Retail Revenue before Rate Discounts which is the Department's retail revenue requirement. Symbolically, let **RR** equal the revenue requirement and let **OMR** stand for all the **O**ther **M**ajor **R**evenue sources, thus, Category 1 = **RR** + **OMR** .

(Category 2) Cash to or for major operational categories. Let **MOC** stand for all these **M**ajor **O**perational **C**ategories, Category 2 = **MOC**.

(Category 3) **C**ash **A**vailable for **D**ebt Service. Let **CAD** equal this category which equals the difference between the first two categories, Category 3 = **CAD**.

(Category 4) Cash paid for **D**ebt **S**ervice, city taxes, and some other accounts. Let **DS** stand for debt service and **OCO** stand for these **O**ther **C**ash **O**utlays, Category 4 = **DS** + **OCO**.

(Category 5) The differin the Summary chapter ence between categories 3 and 4 equals Cash from Operations. This plus cash from **C**ontributions **i**n **A**id of **C**onstruction and bond proceeds equals the total for category 6. Let **CO** stand for **C**ash from **O**perations, **CIAC** stand for contributions and **B** stand for **B**ond proceeds, hence, Category 5 = **CO** + **CIAC** + **B**.

(Category 6) Cash for **T**otal **C**apital and conservation projects and some deferred charges. Let **TotCap** stand for all these expenditures, Category 6 = **TotCap**..

In words, as mentioned above, revenue requirement plus other major revenue sources less major operational categories equal cash available for debt service. In terms of categories this is:

Category 1 – Category 2 = Category 3

In symbols this is:

RR + **OMR – MOC** = **CAD**

Continuing in words, the cash available for debt service coverage should, looking forward in a planning sense, equal the financial policy debt service coverage ratio multiplied by the debt service. In symbols this is:

CAD = **Ratio** * **DS**

Thus, we can say that in a planning sense:

RR + **OMR – MOC** = **Ratio** * **DS**

And, note from Table 2 in the Summary chapter that

Ratio = (**RR** + **OMR – MOC**) / **DS** satisfies desired target ratios for 2010 and subsequent years, i.e., it meets the assumed financial planning guidelines for debt service coverage. Also note that if **RR** were reduced without an offsetting increase in **OMR** or decrease in **MOC**, that the **Ratio** would not meet financial policy standards since **DS** is set by borrowing action in previous years.

Rearranging either of the last two equations, we see:

RR = **MOC – OMR** + **Ratio** * **DS**

That is, planning year revenue requirement equals planning year major operational categories less planning year other major sources of revenue plus debt service in the planning year multiplied by the debt service coverage ratio. Consequently, revenue requirements for the planning year is not affected by cash transactions in Categories 5 and 6, nor by the other cash outlays in Category 4 beyond direct debt service obligations.

This report has illustrated that there is relatively little that can be done to increase other major sources of revenue or to reduce the major expenses. Planning year debt service, as mentioned, is fixed; it is set by borrowings in previous years. Thus, if we take planning year major operational categories and other major sources of revenue as fixed, then planning year revenue requirement is determined by the debt service coverage ratio.

The lower is that ratio, the lower will be the revenue requirement. However, there are practical constraints on how low that debt service coverage ratio can be set given the necessity to continue to borrow substantial amounts of money from the bond market. People and organizations that buy bonds need to be assured that they will be repaid and the lower is the coverage ratio, the less secure they will feel and the more difficult or expensive it will be to borrow.

It is the Department's belief, however, based on discussions with bond counsel, that if the proposed PRAM is adopted as policy the coverage ratio can be lowered somewhat with no deleterious effect on the Department's ability to borrow or on the interest rate it would need to pay for the borrowing. With a lower debt service coverage ratio, the revenue requirement and average system rate can be reduced. Without the PRAM, or its equivalent, the Department believes it will be difficult to borrow or it will need to pay a higher interest rate than the rate associated with its current bond rating.

Returning, for the moment, to major expenses that the Department determines are necessary to operate the Department in a good and orderly manner, it is important to recognize that bond covenants on the $1.3+ billion existing debt assume that the Department will be maintained in good operational order. Significant reductions to planned expenses the Department considers to be prudent for sound maintenance and operation of the system could open the question whether the covenants were being followed.

To continue working with the relationships among categories and elements of Table 1, the amount of cash available for Category 6, comprising all identified capital expenditures, equals cash from all major sources less Cash for all major expenses less cash for debt service and other financial expenses (such as City taxes) plus cash from other sources (CIAC and Bonds).

Expressed in terms of the categories and the last two terms in the previous sentence (CIAC and Bonds) this is:

Category 6 = Category 1 – Category 2 – Category 4 + **CIAC** + **B**

This can be rearranged as:

Category 1= Category 2 + Category 4 – **CIAC** – **B** + Category 6

Finally, substituting for these category terms and again rearranging a bit we have

RR = **MOC** – **OMR** + **DS** + **OCO** – **CIAC** – **B** + **TotCap**

From this last equation it appears that **RR** can be reduced by decreasing **TotCap** or increasing **B**, assuming the other terms do not change. Mathematically, that is correct. However, as noted above, reducing **RR** without an offsetting increase in **OMR** or decrease in **MOC** would not satisfy the debt service coverage ratio. Thus, assuming that the debt service coverage ratio is to be satisfied, attempts to reduce capital projects in the current planning year or increase bond borrowing, by themselves, provide no assistance in reducing revenue requirement that year.

Reducing capital expenditures and bond proceeds by equal amounts simultaneously also would not affect current rates but would reduce future rates. Before doing that, though, it would be necessary to ensure that all necessary capital projects are undertaken to stay within the guidelines of current bond covenants requiring the utility be maintained in good order. The capital projects assumed in this *RRA* are predicated on the notion that they are necessary for the proper operation of the utility.

The next table presents data from the cash flow table, Table 1, in the Summary chapter for the years 2010 – 2012 as well as the debt service coverage ratios from Table 3 in that chapter. The data show the total amounts associated with the various cash from and to categories and identified elements of the cash flow table. The revenue requirements, the subject of this report, are identified as the symbol **RR** and are presented in bold characters highlighted by a grey bar. The bottom portion of the table presents the various relationships mentioned in the text above.

Category or Symbol	Description	Cash Flow 2010-2012 Ratio and Millions of Dollars 2010	2011	2012
Ratio	Debt Service Coverage Ratio	**1.6**	**1.7**	**1.8**
Cat 1	Cash from Major Revenue Sources	777.9611	816.9201	849.0413
RR	**Revenue Requirement**	**587.7628**	**629.5538**	**690.2859**
OMR	Cash from Other Major Revenue Sources	190.1983	187.3663	158.7554
Cat 2	Cash to Major Operational Categories	536.8521	545.9964	541.2264
MOC	Cash to Major Operational Categories	536.8521	545.9964	541.2264
Cat 3	Cash Available for Debt Service	241.1090	270.9237	307.8149
CAD	Cash Available for Debt Service	241.1090	270.9237	307.8149
Cat 4	Debt service & other accounts	187.0908	208.3859	224.2338
DS	Debt Service	150.6931	159.3669	171.0083
OCO	Other Cash Outlays	36.3977	49.0190	53.2255
Cat 5	Cash available for Capital Projects	260.0774	241.9623	277.7098
CO	Cash from Operations	54.0182	62.5378	83.5811
CIAC	Contributions in Aid of Construction	29.7281	30.7500	33.8220
B	Bond Proceeds	176.3312	148.6745	160.3067
Cat 6	Total Capital & Conservation	260.0774	241.9623	277.7098
TotCap	Total Capital & Conservation	260.0774	241.9623	277.7098

Relationships

Category 3 - Category 4 = Cash from Operations	54.0182	62.5378	83.5811
Category 1 - Category 2 = Category 3	241.1090	270.9237	307.8149
OR + OMR - MOC = CAD	241.1090	270.9237	307.8149
CAD = Ratio * DS	241.1090	270.9237	307.8149
RR + OMR - MOC = Ratio * DS	241.1090	270.9237	307.8149
Ratio = (RR + OMR - MOC) / DS	1.6	1.7	1.8
RR = MOC - OMR + Ratio * DS	587.7628	629.5538	690.2859
Category 6 = Cat 1 - Cat 2 - Cat 4 + CIAC + B	260.0774	241.9623	277.7098
Category 1 = Cat 2 + Cat 4 - CIAC - B + Cat 6	777.9611	816.9201	849.0413
RR = MOC - OMR + DS + OCO - CIAC - B + TotCap	587.7628	629.5538	690.2859