PROPOSED
REVENUE REQUIREMENTS
ANALYSIS

2011 – 2012

Seattle City Light
October 2010

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Introduction

I.1 Introduction

This report, the *Proposed Revenue Requirements Analysis for 2011-2012 (RRA)*, discusses the revenue requirement for City Light rates that would become effective January 1, 2011 and January 1, 2012.

A detailed explanation of the rate-setting process can be found in the document, *Seattle City Light Guide to Rate Making*, dated September 2009. The *2011-2012 Proposed Budget* is the foundation of this *RRA*. The Budget authorizes City Light to acquire the resources needed to achieve its mission to "exceed our customers' expectations in producing and delivering environmentally responsible, safe, low cost and reliable power."

I.2 *RRA* Methodology

City Council Resolution 31187, passed in March of 2010, directs City Light to set electric rates at levels sufficient to achieve a debt service coverage ratio of 1.8, so this is the basis for the calculation of revenue requirements. The revenue requirement is the amount of retail revenue that yields Cash Available for Debt Service Coverage that equals 1.8 times the amount of debt service.

City Light's rate setting methodology is based on a "cash flow" approach rather than on the income statement. The cash flow statement's bottom line is the amount available for debt service coverage, the metric designated by the financial policy for rate setting. In contrast, net income includes expenses and revenues that are not cash, and there are also cash flows that do not appear on the income statement. Examples of non-cash transactions found on the income statement are depreciation and mark-to-market valuation for certain energy purchases and sales. Cash transactions typically missing from an income statement include things like cash from suburban customers to pay for undergrounding. The entire amount to be received as payment for an undergrounding project is recorded as income in the year in which the project is completed, even though it might not actually be received until as much as 25 years later. For those interested, an income statement is shown as Table 1.01 in Appendix 1.

The cash flow forecast used to derive the 2011 and 2012 revenue requirements is summarized in Table S1 - Cash Flow, found at the beginning of the Summary chapter. Each line in Table S1 beginning with "Cash from…" is akin to revenue, and generally accounts for cash flowing into the Department, whereas lines beginning with "Cash to…" are akin to costs, and generally account for cash going out of the Department. A small number of lines in the cash flow represent cash flowing from one cash account to another cash account.

There are two notable changes between the methodology used to derive the revenue requirement for 2010 and the current process being used for 2011 and 2012. First, the City Light Financial

Planning Unit transitioned to a new financial model in early 2010. Therefore, the *2010 Rate Study* was produced based on outputs from the now-legacy Financial Planning Model (FPM), and this *RRA* is based on outputs from the new model, "UIPlanner". The old and new models produce almost identical results by design; UIPlanner was implemented to mirror the algorithms and assumptions from the FPM. However, minor differences in computation, along with corrections and improvements made during the migration process contributed to some revenue requirement differences. Second, the financial policies were changed between the two rate reviews, though practically this change had no impact on rates since the determining constraint for both studies was 1.8 times debt service coverage.

I.3 *RRA* and Rates

When conducting a comprehensive rate review, there are three phases to the rate making process: revenue requirement, cost allocation and rate design. Cost allocation allocates the revenue requirements among functional cost components, and rate design is the process of shaping rates, charges, and credits for customer classes so that each class contributes their fair portion of the revenue requirement. The last comprehensive rate review took place in 2006 and established rates for 2007 and 2008[1], and the cost allocation and rate design established in that process and currently in effect were retained for 2010. They are retained for the 2011-2012 review as well. When rates are updated without updating cost allocation and rate design, this is commonly referred to as an "across-the-board" rate change.

An across-the-board rate change might be implemented as a consistent cents-per-kWh adjustment on the energy portion of each customer class' rates. The automatic BPA pass-through utilizes this approach. Alternatively, the rate change may be implemented as a consistent percentage increase across all components of each customer class' rates. In 2010, the rate adjustment used the latter approach, and this is the proposed approach for this rate review as well.

I.4 *RRA* Organization

The *RRA* provides documentation and analysis of the drivers of the revenue requirement for 2011 and 2012, focusing when appropriate on the changes between the forecast used to determine the 2010 revenue requirement and the current forecast for 2011 and 2012. It does not compare the forecast with the actual financial results for any historical year, nor does it compare the current revenue requirement forecast for 2011 and 2012 to any previous revenue requirement forecast for these years.

The Summary chapter is an executive summary of the revenue requirement for 2011 and 2012 relative to the revenue requirement in the 2010 Rate Study. Subsequent chapters are devoted to

[1]Some suburban rates have changed since then to reflect special undergrounding projects there which those customers will pay for as well as reflecting some changes in payments requested by suburban cities which have franchise agreements with City Light. Changes in suburban rates for this latter reason were approved by City Council.

explaining each of the 18 “Cash to/ Cash from” lines in Table S1, one chapter per line, with the exception of the second line, Cash from RSA (Rate Stabilization Account) Surcharge, which is discussed as part of retail revenue and is covered in Chapters 1 and 9. Chapters 1-9 discuss the cash flows that directly determine the revenue requirement for 2011 and 2012. Each of these chapters explains how that particular line is calculated, and why it is important, as well as how and why the forecast for 2011 and 2012 differs from the amount in the *2010 Rate Study*. Chapters 10-17 discuss cash flow lines that do not directly impact revenue requirements. These items (e.g., capital spending, debt issued) do have a cash impact that indirectly influences revenue requirements via debt service. However, this indirect impact is spread across a number of years, and therefore the effect of changes in these cash flow line items might have little impact on the specific revenue requirements discussed in this *RRA*. For this reason, these chapters present forecast data for 2011-2012, but may not discuss differences from the *2010 Rate Study*, since this comparison is not particularly helpful in understanding the revenue requirement for this *RRA*. Finally, Chapter 18 presents a high level discussion of the six-year rate outlook.

This *RRA* has five appendices. Appendix 1 contains a comprehensive set of UIPlanner Financial Model output reports for 2009-2016. Appendix 2 describes the Rate Stabilization Account (RSA). Appendix 3 discusses the wholesale revenue forecast model and assumptions. Appendix 4 contains information on the BPA pass-through and a derivation of its impact on rates. Appendix 5 contains rate schedules showing the new rates.

Summary of the Revenue Requirements Analysis

S.1 Overview

This chapter presents a summary of changes in revenue requirements underlying the rate adjustments for 2011 and 2012.

This summary describes how the revenue requirements are determined and how they affect the Department's ability to meet its financial policy targets. It also identifies the major sources of change between the prior *2010 Rate Study*, which is the basis for the current rates, and the 2011-2012 revenue requirements in this *RRA*.

S.2 How Revenue Requirements Are Determined

The objective of the Revenue Requirements Analysis is to determine the amount of revenue that the Department must collect from customers in a given calendar year to cover operating costs and meet Council-mandated financial policies.

Operating costs and capital expenditure levels are determined as part of Seattle City Light's biennial budget process. Budgeted expenses are set to ensure that the Department will have the staff and financial resources necessary to support key activities and projects. Projections of operations and maintenance expenses, capital expenditures, and other sources of revenue determine the amount of revenue required from customers, which in turn determines the retail rates.

In March of 2010, the City Council passed Resolution 31187 establishing financial policies for setting electric rates. The resolution specifies a rate setting guideline of 1.8 times debt service coverage. Therefore, in any given year the revenue requirement is defined as the amount of retail revenue required such that Cash Available for Debt Service is equal to 1.8 times the total debt service.

Table S1 shows the projected Cash Flow for 2010-12. The first line in the table (Cash from Retail Power Sales before Discounts) is the revenue requirement. It is the amount of revenue that must be collected from customers to cover all costs including power purchases, operations, debt service, taxes and other expenditures above what is covered by revenues from wholesale power sales and other sources. Note that in Table S1, the Cash Available for Debt Service is equal to 1.8 times the Cash to Debt Service for each of the years 2010, 2011 and 2012.

Table S1
Cash Flow
$ millions

	2010 Rate Study	Forecast 2011	Forecast 2012
Cash from Retail Power Sales before Discounts	$614.8	$651.5	$699.2
Cash from RSA Surcharge		11.7	0.0
Cash from Wholesale Power Sales, Net	120.0	110.5	102.1
Cash from All Other Sources	70.4	70.8	70.2
Cash to Rate Stabilization Account	0.0	(32.5)	(2.9)
Cash to Power Contracts	(289.3)	(282.8)	(289.3)
Cash to Operations	(202.2)	(226.6)	(219.7)
Cash to Rate Discounts	(6.5)	(6.6)	(7.1)
Cash to Uncollectable Revenue	(5.5)	(6.0)	(6.3)
Cash to State Taxes and Franchise Payments	(31.2)	(33.3)	(34.6)
Cash Available for Debt Service	**$270.5**	**$256.8**	**$311.6**
Cash to City Taxes	(38.6)	(41.4)	(43.3)
Cash to All Other Purposes	(3.5)	(0.7)	(1.2)
Cash to Debt Service	(150.7)	(142.7)	(173.1)
Cash from Operations	**$77.8**	**$72.0**	**$94.1**
Cash from Contributions	29.7	31.6	19.5
Cash from Bond Proceeds	148.9	188.4	212.7
Cash to Capital, Conservation and Deferred O&M	$256.4	$292.0	$326.3

S.3 Changes in Rates

Table S2 displays the changes in retail rates required to produce the cash flows from Table S1. As indicated, proposed average rate increases are 4.3% in 2011 and 4.2% in 2012. Since residential customers are often more familiar with rates expressed as monthly bill impacts rather than in terms of kWh, the table also displays the effect of rate changes on the average monthly residential bill.

In addition to the change in average system rates on January 1 of each year, this table shows the BPA pass-through, which is adjusted as needed on October 1 of each year. The BPA pass-through is a rate mechanism that allows City Light to pass through to retail customers any changes in amounts charged by BPA arising from changes in BPA's rate schedules.

A rate component that is conspicuously absent from the table below is the RSA surcharge. The RSA surcharge is similar to the BPA pass-through in that rate changes are enacted outside the typical rate ordinance process. However, they are different in that BPA pass-throughs are true rate changes, and base rate changes (such as the ones discussed in this document) are applied on top of them. RSA surcharges sit on top of base rates, and so existing surcharges are not figured into rate increases. Therefore, the proposed 4.3% January 1, 2011 increase is applied on top of the average system rate including the October 1, 2010 BPA pass-through. Then, the appropriate RSA surcharge is applied on top of this average system rate. Because RSA surcharges are downstream of base rate changes, they are only peripherally related to this RRA and the rates that result from it.

The BPA pass-through is added onto the After Rate Change rate for that year and the combined total, which is shown in the bottom line, is the basis for the Before Rate Change rate for the following year. (For more information on the calculation of the BPA pass-through, see Appendix 4.)

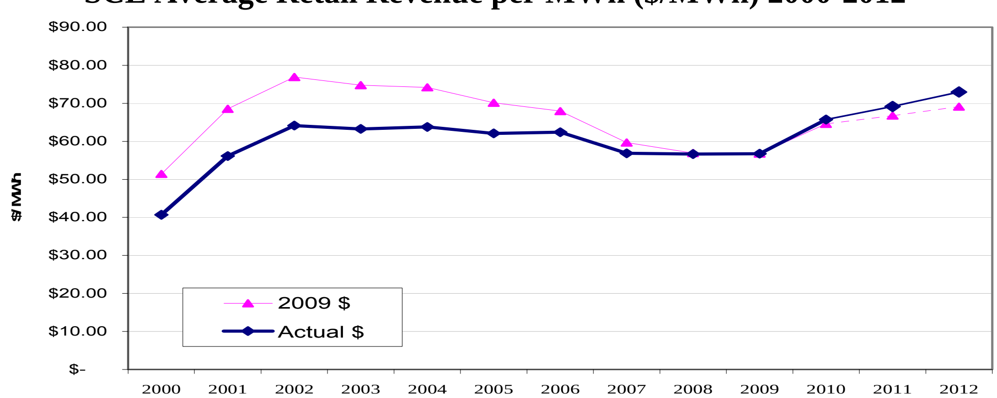
Table S2
Changes in Average Rates and Monthly Bills

	2010	2011	2012
Average System Rate ($ per MWh)			
Before Rate Change (effective Jan 1)	$57.47	$65.99	$70.04
After Rate Change	$65.41	$68.84	$72.95
Difference	$7.94	$2.85	$2.91
Percent Difference	13.8%	4.3%	4.2%
Average Residential Monthly Bill			
Before Rate Change (effective Jan 1)	$44.68	$51.31	$54.45
After Rate Change	$50.85	$53.52	$56.72
Difference	$6.17	$2.21	$2.27
Percent Difference	13.8%	4.3%	4.2%
BPA Pass Through Effective Oct 1 ($ per MWh)	$0.30	$1.20	$0.00
Percent Change to Average System Rate	0%	2%	0%
Average System Rate After BPA Pass Through	$65.71	$70.04	$72.95

The inconsistency between 2010 and 2011 average rate is due to alterations to billing determinants since the previous rate review, which increased the calculated average system rate from $65.71 to $65.99. Billing determinants are the assumption of kwh and kw by rate class which determine the amount of retail revenue collected given a particular rate.

Figure S1 presents average rates in a historical context, including the projected increases for 2011-12.

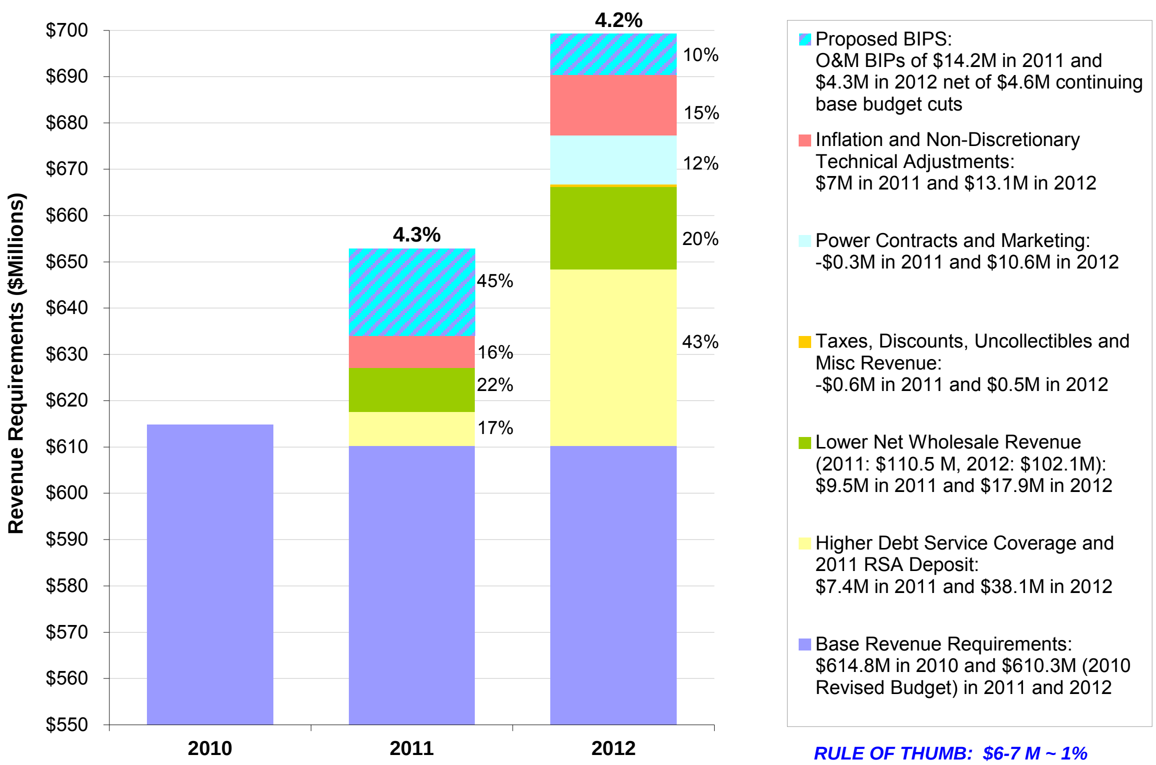
Figure S1
SCL Average Retail Revenue per MWh ($/MWh) 2000-2012



S.4 Revenue Requirements – Graphical Summary View

Figure S2 below is a high-level pictorial view of the revenue requirement drivers of the proposed 4.3% and 4.2% rate increases for 2011 and 2012. In this section we provide a very high level explanation of the main drivers behind the increase in revenue requirements for 2011 and 2012. A more in-depth discussion can be found in the next section of this Summary chapter, and the full *RRA* is comprised of chapters detailing each individual factor.

Figure S2
High-Level Revenue Requirements Drivers



2011 Revenue Requirement Drivers
Major contributors to 2011 rates are approved changes to the Department's Operations and Maintenance (O&M) budget, documented in the budget process through Budget Issue Papers (BIPs). BIPs describe budget decreases and mandatory technical adjustments as well as new programs. In this RRA, technical adjustments have been separated from other BIPs, to differentiate non-discretionary budget changes from discretionary additions. To save money in 2010 City Light cut $9 million dollars from the $615 million base budget. About half of these budget reductions were continued into 2011 and 2012 to help mitigate the rate increases, which is why the base revenue requirement is $4.6 million less than 2010 for these two years. The striped bar shows 2011 BIPs of $18.8 million, but combining these with the continuing cuts results in a net addition of $14.2 million.

For this chart, BIPs have been separated from non-controllable O&M changes, which are shown in the red bar. This bar shows increases in O&M due to inflation and technical adjustments reflecting changes such as increased pension costs and increased City cost allocation funding.

The turquoise bar shows forecasted changes in costs and revenues for: long-term power contracts, power marketing revenues net of expenses, toxic clean up payments, and greenhouse gas offsets. In aggregate, these components offset one another, yielding no rate impact for 2011.

Another significant contributor for 2011 is net wholesale revenue, which, at $110.5 million, is $9.5 million lower than the *2010 Rate Study* amount. This is due to a change in the methodology for deriving this value (moving from a forecast to a historical average) for rate setting purposes. However, both lower regional energy prices and lower generation estimates also support this reduction.

While changes in debt service and the Rate Stabilization Account (RSA) deposit are both major changes for 2011, their net impact on 2011 rates (shown in the yellow bar) is small because they offset one another. Table S3 below shows a breakdown of these component drivers. The Department completed a $792 million debt issue in 2010, about two-thirds of which was refunding of the old debt, and the remaining one-third was new money. The new money portion, along with a projected debt issue in early 2011, increases debt service, while the refunding decreases it. The refunding savings are substantial for 2011 because the issue was structured to maximize the savings in this year so that more cash might be available to help initially fund the RSA. Funding the RSA to its $100 million target by the end of 2011 requires a major one-time cash outlay, and per the terms of the RSA accounting treatment, funds deposited into the RSA cannot count towards debt service coverage. The rate benefit of refunding is 1.8 times the savings, because of coverage requirements. Therefore, even though the refunding savings amount is deposited into the RSA, there is still additional rate benefit.

Table S3
Debt Service and RSA Deposits
Change between 2010 Rate Study and 2011 Forecast
$ millions

Debt Service	$m
Increase in Debt Service from 2010	$14.0
Refunding Savings	(22.0)
Total Change in Debt Service	(8.0)
Change in Debt Service Coverage at 1.8x	**(14.5)**
RSA Deposit	
Total RSA Deposit (needed to get to $100 M)	32.5
Surcharge Revenue (net of taxes)	(10.6)
Cash from Ops Needed for 2011 RSA Deposit	**21.9**
Total Change	**$7.4**

2012 Revenue Requirement Drivers
The single largest contributor to higher rates for 2012 is debt service. The large yellow bar reflects higher debt service due to the 2010 bond issue, plus additional debt service from projected issues in both 2011 and 2012. Whereas refunding savings more than offsets increases in debt service for 2011, only about $3 million in savings was structured into 2012. Therefore, 2012 reflects nearly the full impact of increased debt service coverage stemming from the new debt.

Another contributor is net wholesale revenue, which is $8.4 million lower than the projection for 2011 (and cumulatively, $17.9 million lower than the budgeted amount for 2010). The calculation of the 2012 net wholesale revenue baseline uses the years 2002-2010, and including preliminary results from 2010 (a poor wholesale revenue year) brings down the average substantially.

Costs associated with power contracts and other miscellaneous factors (turquoise bar) are also increasing in 2012, most significantly due to I-937[2] compliance needs. When I-937 goes into effect in 2012, sales of excess Renewable Energy Credits (also known as RECs, or Green Tags) will drop off by $3.4 million since City Light will need them to meet I-937 requirements. City Light also anticipates acquiring an additional $3.5 million in new renewables in 2012, to continue to ramp up to the higher I-937 standards in 2016.

The impact of BIPs on the 2012 revenue requirement has been minimized because the Department, recognizing that debt service would already present substantial upward rate pressure, modified the budget to keep overall expenditures as low as possible. Note that 2012 BIPs, which are $4.3 million net of $4.6 million in continued cuts, are actually $10 million lower than 2011 BIPs.

S.5 Revenue Requirements – Component View

Table S4 is a comprehensive comparison of the elements of the current projected revenue requirements in 2011-12 with those used to set rates for 2010. It is comprised of the components shown in Table S1 that directly impact the revenue requirements, reconfigured to show their relative impact on the rate increase.

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, or “gap”, is shown in the “Gap $” column. The gap is divided by the projected retail load in order to show the effect of each change in terms of $/MWh, and is displayed in the “$ per MWh” column. The “% Change” column compares the $/MWh result to the average system rate in 2010 (shown in Table S2) before the rate change associated with the new revenue requirement. Note that the sum of all the lower elements in Table S4 equals the amount shown in the top row.

[2] Washington State Initiative I-937 requires utilities to obtain 15% of their electricity from renewable resources by 2020, with incremental steps of 3% by 2012 and 9% by 2016.

Table S4
Changes in Revenue Requirements
from 2010 Rate Forecast to 2011-12 Rate Forecast

$ millions

	Rate Study 2010	Forecast 2011: 2011	2010 - 2011 Gap $	Gap $ per Mwh	% Change	Forecast 2012: 2012	2011 - 2012 Gap $	Gap $ per Mwh	% Change
Cash from Projected Rate Increase	**$0.0**	**$26.7**	**$26.7**	**$2.8**	**4.3%**	**$55.1**	**$28.4**	**$3.0**	**4.2%**
is the sum of									
Cash from Retail Power Sales before Discounts, without Rate Increase	($614.8)	($624.9)	($10.1)	($0.7)	(1.6%)	($644.2)	($19.3)	($1.1)	(2.9%)
Cash from RSA Surcharge	0.0	(11.7)	(11.7)	(1.2)	(1.9%)	0.0	11.7	1.2	1.7%
Cash from Wholesale Power, Net	(120.0)	(110.5)	9.5	1.0	1.5%	(102.1)	8.4	0.9	1.3%
Cash from Other Sources	(70.4)	(70.8)	(0.4)	(0.0)	(0.1%)	(70.2)	0.7	0.1	0.1%
Cash to Rate Stabilization Account	0.0	32.5	32.5	3.4	5.2%	2.9	(29.5)	(3.1)	(4.4%)
Cash to Power Contracts	289.3	282.8	(6.4)	(0.7)	(1.0%)	289.3	6.5	0.7	1.0%
Cash to Operations	202.2	226.6	24.4	2.6	3.9%	219.7	(6.9)	(0.7)	(1.0%)
Cash to Rate Discounts	6.5	6.6	0.1	0.0	0.0%	7.1	0.5	0.1	0.1%
Cash to Uncollectible Revenue	5.5	6.0	0.4	0.0	0.1%	6.3	0.3	0.0	0.0%
Cash to State Taxes and Franchise Payments	31.2	33.3	2.1	0.2	0.3%	34.6	1.3	0.1	0.2%
Cash to Debt Service Coverage	270.5	256.8	(13.7)	(1.5)	(2.2%)	311.6	54.8	5.7	8.2%

The individual components of Table S4 are explained in further detail below. Additionally, each of these components and its impact on the revenue requirement is explained at length in the subsequent chapters of this document.

Cash from Projected Rate Increase and Cash from Retail Power Sales before Discounts

The sum of the absolute value of Cash from Projected Rate Increase and Cash from Retail Power Sales before Discounts, without Rate Increase, equals the line on Table S1 called Cash from Retail Power Sales before Discounts, otherwise known as the revenue requirement. In Table S4, the revenue requirement is separated into these two components so as to single out cash resulting from the rate change.

Cash from Retail Power Sales before Discounts, without Rate Increase, is the amount of cash from retail sales that would be realized without any base rate increases for 2011 or 2012. In other words, this is revenue from base rates that were set by the *2010 Rate Study*, updated for small subsequent BPA retail rate pass-throughs. The breakdown of the components of Cash from Retail Power Sales before Discounts, without Rate Increase, is shown in Table S5.

BPA pass-through rate changes are projected for October 2010 and October 2011. City Light's ability to pass through increases in BPA costs to retail customers lowers the amount of the additional revenue requirement that must be collected by increasing base rates.

Table S5
Changes in Retail Power Sales Components

(Million Dollars)

		Forecast 2011				Forecast 2012			
	Rate Study 2010	2011	2010 - 2011 Gap $	Gap $ per Mwh	% Change	2012	2011 - 2012 Gap $	Gap $ per Mwh	% Change
Cash from Retail Power Sales before Discounts, without Rate Increase	**($614.8)**	**($624.9)**	**($10.1)**	**($1.1)**	**($0.0)**	**($644.2)**	**($19.3)**	**($2.0)**	**($0.0)**
equals									
Cash from Retail Power Sales at 2010 Rate Study Average Annual Rate	(614.0)	(619.0)	(4.9)	(0.5)	(0.8%)	(629.8)	(10.8)	(1.1)	(1.6%)
Cash from BPA Pass-Through Implemented Oct 1, 2010	(0.7)	(2.8)	(2.1)	(0.2)	(0.3%)	(2.9)	(0.0)	(0.0)	(0.0%)
Cash from BPA Pass-Through to be Implemented Oct 1, 2011	-	(3.1)	(3.1)	(0.3)	(0.5%)	(11.5)	(8.4)	(0.9)	(1.3%)

Changes in this rate component from year to year are due to changes in customer load profiles, suburban city rate increases per franchise agreements, and other patterns of use affecting retail revenue. These forecasted rate and load pattern changes allow City Light to collect $4.9 million more revenue and thus, lower the amount of additional revenue required from further retail rate increases. This component does not include any revenue from RSA surcharges in 2010 or any other year. These are kept separate from base rate calculations and are discussed in the next section.

The Cash from Projected Rate Increase represents the amount that must be collected by increasing rates from the amount set by the 2010 Rate Study.

Cash from Wholesale Power Sales, Net

Table S1 shows that Cash from Wholesale Power Sales, Net (also known as net wholesale revenue) are projected to decrease from 2010 to 2011-12. Table S4 shows that the projections of $110.5 million and $102.1 million for 2011 and for 2012, respectively, are both lower than the $120.0 million assumed for the *2010 Rate Study*.

The *2010 Rate Study* assumption was based on a forecast of surplus energy and wholesale market prices. For the 2011-2012 Rate Study, the Department is using a simple average of historical actuals, shown below.

Table S6
Derivation of Net Wholesale Revenue ($M)
$ millions

2002 Actual	$ 89.6
2003 Actual	$ 113.4
2004 Actual	$ 113.6
2005 Actual	$ 87.4
2006 Actual	$ 140.1
2007 Actual	$ 137.3
2008 Actual	$ 134.4
2009 Actual	$ 68.2
2010 Estimate	$ 35.0
2002-9 Average	**$ 110.5**
2002-10 Average	**$ 102.1**

This approach is consistent with the methodology called for in RSA Ordinance 123260, which was passed by the City Council in March, 2010. The Ordinance requires the RSA baseline to be the same as the amount of net wholesale revenue assumed for the purpose of setting rates. It further specifies that the baseline should be determined by simple historical average, "unless, after consideration of additional information, the City Council determines that a different methodology is warranted."

As of April 30, 2010 when the budget process began, City Light forecasts (using the same methodology as used in the *2010 Rate Study*) with an average water assumption and current market prices returned values within $1 million of the historical average methodology, which was not compelling evidence to advocate adopting a different assumption. As of September 17, 2010 forecasts show a reduced outlook, with 2011 wholesale revenue at $83.7 million, and 2012 at $96.6 million. Negative variances between the expected outlook and the baseline increase the likelihood that the RSA will be drawn down, and that RSA surcharges will be applied to rates. Accordingly, this is a matter that City Light will continue to monitor throughout 2010.

Cash from All Other Sources
Cash from All Other Sources includes miscellaneous cash sources such as power contracts (e.g., long-term power sales, BPA credits), power marketing activities, investments, and sales of surplus property. A breakdown of these components is shown in the table below.

Table S7
Summary of Cash from All Other Sources
$ millions

	Rate Study 2010	Forecast 2011	Change 2010 - 2011	Forecast 2012	Change 2011 - 2012
Power Contracts	$22.3	$21.2	($1.1)	$20.6	($0.6)
Power Marketing, Net	$17.0	$15.2	($1.8)	$8.2	($7.0)
Other	$31.1	$34.4	$3.3	$41.4	$6.9
Total Cash from All Other Sources	**$70.4**	**$70.8**	**$0.4**	**$70.2**	**($0.7)**

The decrease in cash from power contracts is primarily due to reduced credits from BPA for conservation and renewables. Power marketing, net of costs, is projected to decrease in 2011 and then decline substantially in 2012. City Light generates revenue from transmission sales, basis sales, capacity sales, and other power-related services; these revenues are on the decline because of sluggish market prices and fewer opportunities to monetize the Department's assets. In addition, in 2012, revenue from Green Tag sales drops off, since these must be retained to meet the I-937 3% renewable portfolio standard, which goes into effect that year. Reduced sales of reserves and no assumed premium revenues from a Lucky Peak exchange sale are also drivers for the 2012 decline.

Cash from other sources besides power contracts and marketing is projected to be higher in 2011 and also increase for 2012. This sub-category includes cash from a variety of sources such as sales of property, investment income, operating fees, and grants Investment income in particular is growing since cash reserves are growing with the RSA, increasing interest income.

Cash to Power Contracts

Cash to Power Contracts is the sum of cash spent on long term power purchases, wheeling purchases, and Water for Power (FERC administration, land use and water right fees for hydro projects). Overall, these costs are projected to decrease by about $6.4 million between *2010 Rate Study* projections and those for 2011, and increase by $6.5 million between 2011 and 2012. The drivers of these changes are shown in the table below.

Table S8
Summary of Purchased Power Contracts
$ millions

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Bonneville Power Administration	$172.4	$165.9	($6.5)	$163.9	($2.0)
Wind Resources	21.2	21.7	0.6	25.2	3.5
High Ross	13.1	13.1	0.0	13.1	0.0
Lucky Peak	6.1	6.0	(0.1)	6.2	0.2
Grand Coulee	5.0	5.1	0.1	5.2	0.0
Priest Rapids	12.4	11.9	(0.5)	13.1	1.2
SPI Purchase	1.7	2.4	0.7	2.5	0.0
Renewable Resource Acquisitions	0.0	3.5	3.5	7.0	3.5
Columbia Ridge*	2.9	2.8	(0.1)	2.9	0.1
Water for Power (FERC Fees)	9.3	10.5	1.1	11.0	0.5
Wheeling	45.2	39.9	(5.3)	39.2	(0.7)
Total Cash to Power Contracts	**$289.3**	**$282.8**	**($6.4)**	**$289.3**	**$6.5**

(*) Called "IRP Resource" in 2010 Rate Study

A prominent cost increase is Renewable Resource Acquisitions, which is the ramping up purchase of green power resources to help comply with I-937 targets. Wind resource costs are also rising, especially in 2012, because of anticipated new integration and exchange contract terms that will increase the cost of this resource. Offsetting contract cost decreases include the Bonneville Power Administration (BPA) contract and various wheeling expenses. The BPA contract cost declines due to a large $6.1 million Slice true-up payment for 2010, to be received in 2011, and because of reduced power volumes from the new contract which starts October 2011. Wheeling expenses are down due to reduced transmission needs stemming from the new wind contract, and because an anticipated increase in BPA transmission rates did not materialize. Chapter 4 contains more details on power contracts.

Cash to Operations

Cash to Operations is a sum of cash spent on production, transmission, distribution, non-programmatic conservation, customer accounting and administration. Cash to Operations is projected to be $24.4 million higher in 2011 than the *2010 Rate Study* amount, with 2012 projected to decrease by $6.9 million.

Table S9 below shows the main components that drive changes in Cash to Operations. The baseline equals the amount from the *2010 Rate Study*, and inflation is generally assumed at 2%, though labor costs contain reductions that reduce this somewhat.

In 2010 City Light cut $9 million dollars of operating expenses in response to lower than planned wholesale revenue. To help mitigate the rate increases in 2011 and 2012 $4.6 million of these budget reductions were continued in the 2011 and 2012 budget. Also, to distinguish between discretionary and non-discretionary changes to cash to operations, the table shows compulsory technical adjustments, such as increases in pension costs and inter-departmental cost allocations, separate from other BIPs. These are all discussed in more detail in Chapter 5.

The other changes to this part of the forecast are adjustments to reflect changes in costs for toxic cleanup, and greenhouse gas mitigation. These adjustments are not BIPs nor are they due to inflation.

Table S9
Summary of Projected Cash to Operations in 2011 and 2012

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Baseline	$198.7	$198.7	$0.0	$198.7	$0.0
Inflation	0.0	4.1	4.1	8.2	4.1
Budget Reductions	0.0	(4.6)	(4.6)	(4.6)	0.0
BIPs	0.0	18.8	18.8	8.9	(9.9)
Techical Adjustment (BIPs)	0.0	2.9	2.9	4.9	2.0
Toxic Cleanup, Net of Accruals	3.1	5.6	2.5	1.5	(4.1)
Green House Gas Mitigation	0.5	1.1	0.7	2.1	1.0
Cash to Operations	**$202.2**	**$226.6**	**$24.4**	**$219.7**	**($6.9)**

Cash to Rate Discounts

Cash to Rate Discounts is the cash required to fund rate discounts and other services provided to low-income customers. Residential customers that qualify for City Light's low-income rate discount program receive a 60% rate discount over standard residential rates. Typically, the amount of cash needed to supply the discount offered to low-income customers increases proportionately with rates. However, the difference is disproportionately small ($0.1 million) between 2010 and 2011 due to a correction associated with migrating from the legacy Financial

Planning Model used to perform the *2010 Rate Study* to UI Planner, the model used for this study. Rate discounts are projected to increase proportionately with rates between 2011 and 2012, by $0.5 million.

Cash to Uncollectable Revenue
Cash to Uncollectable Revenue is projected at $6.0 million for 2011 and $6.3 million for 2012. Uncollectable revenue is projected to remain stable at around 0.9% of revenue from energy sales to retail customers, equivalent to its average level over the past three years. It is projected to increase slightly in 2011and 2012 over the *2010 Rate Study* amount, commensurate with the overall retail revenue increase.

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 $2.1 million higher than the *2010 Rate Study* amount for 2011, and an additional $1.3 million higher for 2012. The increase is primarily State tax payments, which increase proportionately with the higher retail revenue from new rates. Per City Charter, City taxes are available for debt service payments and therefore are not counted as an expense for purposes of calculating the revenue requirement.

Cash to Rate Stabilization Account
Cash to the Rate Stabilization Account (RSA) is the cash that is transferred from the operating account into the RSA account. Funds that are transferred to the RSA will be recorded as deferred revenue so they will available for debt service coverage when they are withdrawn later to supplement lower than planned wholesale revenue. Cash to the RSA includes RSA surcharge revenue net of taxes and all other cash transfers. In 2011 the Cash to the RSA is projected to be $32.5 million, which is the amount needed in 2011 to reach the $100 million target, plus interest earnings. This amount is made up of $10.6 million in surcharge revenue (net of taxes) with the remainder being attributed to cash from the 2010 bond refinancing savings, plus interest earnings of about $1.4 million. Assuming all revenues and expenses are realized as projected, the RSA will to reach its targeted amount by July 2011. On a planning basis, there are no expected transfers to the RSA in 2012.

Cash to Debt Service Coverage
Cash to Debt Service Coverage for 2011 is $13.7 million lower than the amount in the *2010 Rate Study*. In May 2010, the Department completed a bond issue of $792 million, about two-thirds of which was refunding of old debt; the remaining one-third was new money. Debt structuring moved the bulk of the refinancing savings into 2010 and 2011, which contributed to a large reduction in debt service coverage needs for 2011. This is why debt service is lower in 2011 than in the *2010 Rate Study*, even though the Department’s debt level has increased. Since there are little offsetting refunding savings in 2012, debt service coverage requirements are projected to increase substantially between 2011 and 2012, by $54.8 million. Increases to debt service stem from the 2010 bond issue, as well as projected debt issues of $210 million in early 2011 and $200 million in early 2012.

Chapter 1 - Cash from Retail Power Sales before Discounts

Cash from Retail Power Sales before Discounts for 2011 and 2012 is the primary 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 2011 is $651.5 million and for 2012 is $699.2 million (see Table S1 in the Summary chapter and Table 1.1 in this chapter). These are the revenue requirements for each year. This total reflects the proposed $2.85 per MWh Base Rate Change effective January 1, 2011 and $2.91 per MWh Base Rate Change effective January 1, 2012 shown in Table S2 in the Summary chapter.

This line in the cash flow does not include 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 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 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, peak 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, capacity 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 in "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.

In general, most of the discussion in the remainder of this *RRA* compares the proposed 2011-2012 results with the values for 2010 in the *2010 Rate Study*. These comparisons are useful in explaining changes since the last rate case, but they differ from the information provided in the Summary to explain the immediate effect of the 2011-2012 revenue requirements on currently existing rates.

The values shown for 2011 and 2012 in Table 1.1 are from the 2011-2012 Rate Study. They include all of the rate changes which have been made or are expected to be made before the end of 2012. These[3] include:

- $0.30 per MWh BPA pass-through effective October 1, 2010 (0.5% increase)
- $2.85 per MWh Base Rate Change effective January 1, 2011 (4.3% increase)
- $1.20 per MWh BPA pass-through effective October 1, 2011 (1.7% increase)
- $2.91 per MWh Base Rate Change effective January 1, 2012 (4.2% increase)
- 4.5% surcharge to fund a Rate Stabilization Account (RSA) effective May 1, 2010, decreasing to 3% on April 1, 2011 and ending on June 30, 2011, when the RSA is expected to be fully funded. The RSA is described in more detail in Chapter 9 and Appendix 2.

Note that two of these changes are associated with the automatic BPA pass-through and are not associated with the revenue requirement increase proposed by the Department in this rate case.

As shown in Table 1.1 the annual average rates for 2011 and 2012 are forecast to be $69.17 per MWh (or 6.917 cents/kWh) and $72.95 per MWh (or 7.295 cents/kWh), respectively. These annual average rates include the pass-through of increases in BPA costs starting October 1, 2010 and October 1, 2011.

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

Comparing the 2011 forecast with values for 2010 in the *2010 Rate Study* we see only a small increase in total sales (about 32,000 MWh). Slowness in economic recovery is expected to produce some small increases for some classes (Small and Large General Service) yet decreases

[3] See Table S2 in the Summary chapter for these numbers.

for others (Residential, Medium General Service and High Demand). This variability reflects the expected unevenness of the local economic recovery.

Energy sales are forecasted to grow faster during 2011-2012 than during 2010-2011 because the economic recovery is expected to be further advanced. Comparing 2011 and 2012 forecasted values we see that Sales to Residential Customers are up by about 20,000 MWh, Sales to Small General Service Customers are up by about 31,000 MWh and Sales to other General Service Customers are up about 113,000 MWh. Total Energy Sales are up by about 165,000 MWh.

Retail charges for low income customers are discounted by about 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

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Cash from Retail Power Sales before Discounts	$614,776,081	$651,516,246	$36,740,165	$699,234,056	$47,717,811
Residential Service (Regular)	210,798,868	221,560,383	10,761,515	235,532,700	13,972,317
Residential Service (Assisted)	10,785,251	11,196,032	410,781	11,945,887	749,855
Small General Service	75,802,555	81,138,262	5,335,707	87,899,391	6,761,128
Medium General Service	144,682,683	151,525,315	6,842,632	163,951,099	12,425,784
Large General Service	93,833,516	103,873,873	10,040,357	111,967,924	8,094,051
High Demand General Service	65,772,490	68,424,176	2,651,686	73,291,143	4,866,967
Street and Flood Lights	13,100,718	13,798,204	697,486	14,645,913	847,709
Energy Delivered to Retail Customers (MWh)	9,387,586	9,419,707	32,121	9,584,676	164,969
Residential Service (Regular)	2,801,515	2,790,337	(11,178)	2,809,523	19,185
Residential Service (Assisted)	142,711	143,443	732	144,776	1,333
Small General Service	1,174,544	1,190,709	16,165	1,221,940	31,231
Medium General Service	2,388,381	2,362,283	(26,098)	2,421,953	59,671
Large General Service	1,542,401	1,612,936	70,535	1,646,982	34,046
High Demand General Service	1,243,119	1,225,081	(18,038)	1,244,329	19,248
Street and Flood Lights	94,915	94,919	4	95,173	254
Average Cash Received per MWh Delivered	$65.49	$69.17	$3.68	$72.95	$3.79
Residential Service (Regular)	75.24	79.40	4.16	83.83	4.43
Residential Service (Assisted)	75.57	78.05	2.48	82.51	4.46
Small General Service	64.54	68.14	3.60	71.93	3.79
Medium General Service	60.58	64.14	3.57	67.69	3.55
Large General Service	60.84	64.40	3.56	67.98	3.58
High Demand General Service	52.91	55.85	2.94	58.90	3.05
Street and Flood Lights	138.03	145.37	7.34	153.89	8.52
Cash to Rate Discounts	$6,464,538	$6,581,448	$116,910	$7,064,615	$483,167
Rate Discounts ($/MWh)	$45.30	$45.88	$0.58	$48.80	$2.91
Rate Discounts (%)	60%	60%	0%	60%	0%
Cash from Residential Service (Assisted) after Discounts	$4,320,713	$4,614,584	$293,871	$4,881,272	$266,689
Residential Service (Assisted) Avg Rate after Discounts	$30.28	$32.17	$1.89	$33.72	$1.55

Chapter 2 - Cash from Wholesale Power Sales, Net

Cash from Wholesale Power Sales, Net is the cash derived from the sale of power that is surplus over system load and other obligations. This amount is also commonly referred to as net wholesale revenue. Following the 2000-2001 energy crisis, the Department moved to acquire energy resources at a level significantly exceeding that needed to meet retail demand under normal circumstances. The reasons for this were twofold. First, having excess supply is prudent given that the Department's resources are primarily hydroelectric. This excess provides insurance against the uncertainty of hydro conditions so that even under dry scenarios, the Department's reliance on the wholesale market is limited. Second, given the low cost of hydro power, sales of surplus energy provide a valuable source of revenue for the Department, which helps reduce the retail customer revenue requirement.

About 90% of City Light's power comes from hydroelectric resources. In an average year, City Light's resources produce approximately three million MWh more power than needed to serve customers. However, hydroelectric resource production can vary greatly depending on precipitation and snowpack conditions. City Light could, potentially, have 50% more power than needed, or have almost no surplus in a given year. Net wholesale revenue is the product of net surplus energy and market prices, and the market price of energy is also uncertain and can vary greatly. As a result, actual net wholesale revenue is a very difficult amount to pinpoint. (For a full discussion of the Department's forecast of net wholesale revenue, please see Appendix 3)

Despite efforts to develop robust and accurate hydro generation and revenue forecasts, City Light has often over-estimated net wholesale revenue in recent years. A major culprit has been poor hydro production; the Pacific Northwest has experienced above-average hydro runoff in only two of the years in the last decade. Models to estimate hydro production utilize water records over the past 60-70 years with expected hydro production tending to reflect average water conditions in those years.

Price volatility is also an issue in projecting net wholesale revenue, as seen in the recent economic downturn which contributed to a large reduction in energy prices and wholesale revenues. Both 2009 and 2010, to date, suffered from large wholesale revenue shortfalls (over 50% from budget) because of low prices and poor water conditions, which forced City Light to adopt both difficult spending reductions and retail rate increases.

In response to the volatility of net wholesale revenue observed in recent years, the City Council established, by Ordinance 12360, the Rate Stabilization Account (RSA) in March 2010. The purpose of the RSA is to offset uncertainty in wholesale revenue. A baseline amount for net wholesale revenue is used to set rates for the coming year(s). If the actual amount is lower, the difference is withdrawn from the RSA and if actual wholesale revenue is above the baseline, the difference is added to the RSA. If the RSA balance falls below $90 million, an automatic surcharge will be imposed until the RSA amount reaches its target size of $100 million. The RSA has provisions for additional surcharge rate increases as the RSA balance decreases.

The RSA legislation specifies that the baseline for net wholesale revenue shall be the simple average of such revenue from year 2002 through the last year for which there is complete information "unless, after consideration of additional information, the City Council determines that a different methodology is warranted." For the complete years 2002-2009, the calculated amount of net wholesale revenue is $110.5 million. However, this *2011-2012 Revenue Requirements Analysis* is establishing revenue requirements and retail rates for a two year period when the last year before the start of the new rates is anticipated to have significantly lower net wholesale revenue than any year since 2002. Thus, in City Light's judgment, the value to use in projecting net wholesale revenue for 2012 should include the current best estimate of net wholesale revenue in the current year. Including a preliminary value for 2010 (April 30, 2010 forecast) reduced the initial estimate of net wholesale revenue to $102.1 million. The derivation of the averages is shown in the table below.

Actual Net Wholesale Revenue ($M)

2002	$ 89.6
2003	$ 113.4
2004	$ 113.6
2005	$ 87.4
2006	$ 140.1
2007	$ 137.3
2008	$ 134.4
2009	$ 68.2
2010 Estimate	$ 35.0
2002-2009 Average	**$ 110.5**
2002-2010 Average	**$ 102.1**

As of April 30, 2010 (approximate starting date of the 2011-2012 budget development), applying the same forecast methodology used for the previous RRA with current surplus energy and market prices returned estimates of net wholesale revenue for 2011 and 2012 that were within $1 million of the estimates yielded by the historical averages. This result did not support advocating for a different baseline assumption than the amount derived using the RSA legislation's stipulated process, as modified by the inclusion of the estimate of 2010 net wholesale revenue.

For 2011 and 2012, City Light estimates Net Wholesale Revenue as specified in RSA legislation even though, as of the date of this *RRA*, the Department's forecast is currently tracking slightly lower than the historical averages.

Table 2.1 is derived from data used in the Department's net wholesale revenue model. The table presents data on major factors affecting net wholesale revenue, and shows that Cash from Wholesale Power Sales, Net is projected to decrease between 2010 and 2011-2012. The projections of $110.5 million and $102.1 million for 2011 and for 2012, respectively, are both lower than the $120.0 million assumed in the *2010 Rate Study*. [4]

Looking toward future rate cases, simple averages of net wholesale revenues since 2002, as outlined by the RSA ordinance, may not necessarily be the best estimate of those revenues for setting rates. There may be a possibility that a revision to the Department's model would produce better or more reasonable estimates of net wholesale revenue that would be acceptable to the Council. The thinking behind this possibility is that the current version of the Department's model bases its estimate of net wholesale revenue on average or expected water conditions.

Neighboring utilities Tacoma Power and Snohomish PUD use a rate forecast that assumes hydro production at approximately the 70-80% confidence level, which provides a higher degree of confidence of exceeding this value than the assumption City Light uses. Consequently, there is precedent for choosing a higher confidence level in estimating the amount of net wholesale revenue to use in budgets and rate setting. However, there are real implications of changing to this more conservative confidence level and those implications would suggest not adopting this revision at this time. Adopting the suggestion now would reduce net wholesale revenue which would require either spending reductions or higher rates at a time when both the Department and customers' budgets are already strained. If the wholesale revenue forecast were set around the 70-80% confidence level this would be a $40-50 million reduction over the expected value forecast. This would translate to a base rate increase of roughly 5-7%. City Light and the Council can explore the possibility to adopt this more conservative net wholesale revenue estimate gradually over several years, or this possibility might be considered as part of the next rate review process.

[4] Note that the 2010 Rate Review projected net wholesale revenue at nearly $120 million whereas the current best estimate (September 17, 2010) for 2010 is $54.5 million. These swings depict how sharply and how rapidly estimates of net wholesale revenue can change.

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

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Uses of Power					
MWh of Electric Energy to Loads	14,633,136	14,507,578	(125,558)	13,984,440	(523,138)
Seattle System Load	9,919,004	10,013,905	94,901	10,188,947	175,042
Pend Oreille County	370,022	370,022	0	371,036	1,014
Encroachment	40,166	40,166	0	40,272	106
Energy Exchanges	383,561	383,927	366	90,580	(293,347)
Power Market for Losses	76,318	157,048	80,730	157,490	442
Power Market	3,844,065	3,542,510	(301,555)	3,136,116	(406,394)
Sources of Power					
MWh of Electric Energy from Resources	14,367,371	14,507,578	140,207	13,984,440	(523,138)
City Light Resources	6,271,819	6,373,907	102,088	6,416,588	42,681
Ross	751,587	768,691	17,104	771,538	2,846
Diablo	736,219	749,796	13,577	750,698	903
Gorge	883,690	904,163	20,473	906,155	1,991
Boundary	3,759,711	3,810,504	50,793	3,847,410	36,906
South Fork Tolt	53,829	53,829	0	53,829	0
Cedar Falls+Newhalem	86,783	86,923	140	86,958	35
Long Term Contracts	7,299,453	7,245,277	(54,176)	6,648,439	(596,838)
BPA, Slice+Block	5,639,596	5,371,760	(267,836)	4,989,668	(382,093)
High Ross	310,246	310,246	0	310,246	0
Lucky Peak	292,981	293,347	366	293,622	276
GCPHA	239,763	240,034	271	240,034	0
Priest Rapids	228,414	173,833	(54,581)	174,921	1,088
Wind Resources	402,844	371,144	(31,700)	372,167	1,023
SPI	26,280	26,280	0	26,352	72
Columbia Ridge	50,633	50,633	(0)	50,772	139
Energy Exchanges	108,696	376,000	267,304	129,657	(246,343)
Renewable Resource Acquisition	0	32,000	32,000	61,000	29,000
Spot Market Purchases					
Power Market	796,099	888,394	92,295	919,413	31,019
Cash from Wholesale Power Sales, Net	$119,973,371	$110,500,000	($9,473,371)	$102,100,000	($8,400,000)
MWh of Energy to Wholesales Power Sales, Net	3,047,966	2,654,116	(393,850)	2,216,703	(437,413)
Dollars per MWH of Energy to Power Market	$39.36	$41.63	$2.27	$46.06	$4.43
Dollars per MMBTU of Natural Gas	$5.34	$4.55	($0.79)	$6.33	$1.78
Ratio of Electric Energy Price to Natural Gas Price	7.37	9.14	1.77	7.27	(1.87)

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 be about $70 million in both 2011 and 2012, the same level as in the *2010 Rate Study*.

Table 3.1
Cash from All Other Sources

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Power Contracts	$22,344,800	$21,206,939	($1,137,861)	$20,603,174	($603,765)
Power Marketing, Net	16,960,718	15,207,751	(1,752,967)	8,202,745	(7,005,006)
Other Sources	31,124,641	34,413,871	3,289,230	41,359,580	6,945,709
Cash from All Other Sources	**$70,430,159**	**$70,828,561**	**$398,401**	**$70,165,499**	**($663,062)**
Article 49 Sales to PO County	1,763,888	1,696,984	(66,904)	1,738,071	41,087
Seattle Share of Priest Rapids Revenue	8,590,472	8,200,000	(390,472)	9,500,000	1,300,000
BPA Credit for South Fork Tolt	3,521,368	3,462,462	(58,906)	3,382,347	(80,115)
BPA Conservation & Renewables Credit	2,486,316	1,864,737	(621,579)	0	(1,864,737)
BPA Residential Exchange Credit	5,982,756	5,982,756	0	5,982,756	0
Cash from Power Contracts	**$22,344,800**	**$21,206,939**	**($1,137,861)**	**$20,603,174**	**($603,765)**
Transmission Services	6,579,411	2,189,204	(4,390,207)	2,231,471	42,267
Basis Sales, Net	1,500,000	1,094,400	(405,600)	1,115,016	20,616
Other Services, Net	8,881,307	11,924,147	3,042,839	4,856,258	(7,067,889)
Cash from Power Marketing, Net	**$16,960,718**	**$15,207,751**	**($1,752,967)**	**$8,202,745**	**($7,005,006)**
Other Revenue	20,359,082	21,813,381	1,454,299	22,242,537	429,156
Investments	4,414,213	4,427,862	13,649	10,372,915	5,945,053
Sale of Property	1,725,097	2,546,256	821,159	2,250,000	(296,256)
Suburban Undergrounding	621,676	691,417	69,741	924,094	232,677
Operating Fees and Grants	710,000	300,000	(410,000)	115,000	(185,000)
Distribution Capacity Charge	199,702	204,309	4,607	208,899	4,590
Green Power Programs	1,082,095	2,520,000	1,437,905	3,130,000	610,000
Power Factor Charges	2,612,936	2,525,406	(87,530)	2,745,629	220,223
LESS					
Credits for Transformation	333,658	341,956	8,298	350,236	8,280
Emergency Low-Income Assistance Program	266,502	272,805	6,303	279,258	6,453
Cash from Other Sources	**$31,124,641**	**$34,413,871**	**$3,289,230**	**$41,359,580**	**$6,945,709**

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 its projected changes between 2010 and 2011, and between 2011 and 2012.

3.1 Cash from Power Contracts

Cash from Power Contracts is projected to decrease by $1.1 million from the 2010 forecast to $21.2 million in 2011 and decrease by another $0.6 million from 2011 to $20.6 million in 2012. Most of this decrease is due to the reduced BPA Conservation and Renewables Credit.

3.1.1 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. This withdrawal is expected to continue in 2011 and 2012. The sales revenue is projected to be about $1.7 million in 2011 and slightly over $1.7 million in 2012. The *2010 Rate Study* forecasted this revenue to be around $1.8 million, which is $0.1 million higher than forecast for 2011. The reason for the difference is that the 2010 forecast was extrapolated from 2009 actual historical revenue that included true-up revenue for 2008, whereas forecasts for 2011 and 2012 do not include prior year true-up revenue.

3.1.2 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 contracted to receive a share of the profits derived from the sale of the 30 percent share of Priest Rapids' output starting in November 2009. The sale includes outputs from both Priest Rapids and Wanapum dams. City Light projects that it will receive $8.2 million in revenues from the Priest Rapids project in 2011 and $9.5 million in 2012. 2011 projected revenue is slightly lower than the amount forecast in the *2010 Rate Study* because of lower prices. In 2012, Grant County PUD will be taking more energy from the Priest Rapids project to meet its own load, reducing the amount available for sale, but projected 2012 revenue is higher by $1.3 million in spite of the anticipated reduction in the volume of output for sale because of expectations that prices will go up.

3.1.3 BPA Credit for South Fork Tolt

BPA reimburses Seattle City Light for developing a 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, WA. Under expected water conditions it provides 8.1 average MW. The credit is calculated based on a BPA rate impact test that subtracts the cost of buying power and transmission services from BPA from the cost of developing a new resource which is called the alternative resource cost (AC). The estimate of the cost of buying power from BPA for this purpose is projected to rise nearly 5.5% between 2011 and 2012. The alternative cost is estimated by BPA and stipulated in advance. The AC for 2011 is $96.70 per MWh and is $97.30 per MWh for 2012, an increase of 0.6%. The total credit is projected to decrease by about $59,000 between 2010 and 2011 and decrease by about $80,000 between 2011 and 2012.

3.1.4 BPA Conservation & Renewables Credit

BPA currently provides a Conservation and Renewables Rate Credit to City Light. The Utility claims this credit by reporting qualifying activities to BPA. These activities can be investments in conservation, donations to certain conservation organizations or purchases of renewable resources. 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 months and multiplying the result by 0.50 mills/kWh. The annual amount was determined by multiplying the rounded monthly credit by 12 months. The Conservation Rate Credit was $2.5 million in 2010. Currently City Light expects to receive this credit through September 2011, and that it will amount to $1.9 million in 2011, a decrease of $0.6 million from the 2010 forecast. The current credit ends in September 2011 with the end of the existing BPA power contract and any subsequent credit will be recognized only if such a credit can be negotiated with BPA.

3.1.5 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. The payments in 2011 and 2012 are projected to remain the same as in 2010, about $6.0 million.

3.2 Cash from Power Marketing, Net

City Light generates revenue from basis sales (see definition below), capacity sales and other power-related services. Cash from power marketing activities projected in 2011 is $15.2 million, a decrease of $1.8 million from the *2010 Rate Study*. It is forecast to continue to decrease in 2012 by $7.0 million, to $8.2 million. Reasons for the decrease include lower revenues from transmission services and basis trades in 2011. In 2012, revenue from Green Tag sales drops off, since these must be retained to meet the I-937 3% renewable portfolio standard, which goes into effect that year. In addition, 2012 revenues are also lower because of lower projected capacity sales and no assumed premium revenues from a Lucky Peak exchange sale.

3.2.1 Transmission Services

Under its Point-to-Point (PTP) transmission service agreement with BPA and others, City Light is permitted to market its unused transmission capacity. 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. In addition, City Light has a group of contracts with Snohomish County PUD (SNOPUD) for North Mountain Substation that reimburse City Light for O&M expenditures for the substation and transmission of power to SNOPUD over City Light's Skagit Transmission Lines. Cash from Transmission Services is forecasted to be about $2.2 million in both 2011 and 2012. This is a decrease of $4.4 million from the revenue amount forecasted in the *2010 Rate Study*. $2.0 million of this difference is due to an assumption for additional revenue from monetizing excess transmission capacity in 2010 that was not continued in 2011 or 2012. However, the Department continues to look for opportunities to optimize the value of its transmission assets. The rest of the decrease is explained by the change in BPA rules regarding how its customers are allowed to resell their excess PTP transmission. Prior to the new rules, City Light charged rates to its counterparties that included BPA's charges for the cost of losses and reserves. The new rules allow those BPA costs to be assigned directly to the counterparties. Hence, City Light charges lower rates to the counterparties and, therefore, revenues are forecast to decline.

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 about $1.1 million in both 2011 and 2012. These forecasts are based on sales in 2009 and drier than normal hydro conditions in the last several years. The forecasts of basis sales are, therefore, about $0.4 million lower than were expected for 2010.

3.2.3 Other Services

Cash from other services is a net total that includes revenues from sales of capacity, Green Tags, and reserve energy. 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 energy to counterparties who have the choice of determining the amount and timing of delivery; these are called "capacity sales."

Cash from other services is projected to be $11.9 million in 2011, about $3.0 million higher than the amount forecasted in the *2010 Rate Study*. The increase is mostly due to inflation in prices of services sold and lower expenditures for other services that are purchased in 2011. However, this revenue is forecast to substantially decline in 2012, to $4.9 million. This $7.0 million decrease is due to several factors. First, according to Washington's Renewable Portfolio Standard Initiative 937 (I-937) City Light is required to serve 3% of retail load with eligible renewable resources and/or equivalent renewable energy credits (RECs) by January 1, 2012. Thus, to comply with the I-937 requirement in 2012, the Department will keep most of the energy generated by renewable resources instead of selling it to other entities like it has been doing in the past. This action is projected to reduce Green Tag sales revenue from $4.0 million in 2011 to $0.6 million in 2012. Second, capacity sales are projected to decline by $2.4 million between 2011 and 2012. Lastly, the current forecast assumes sale of the Lucky peak output in 2011 for $1.5 million but no sale in 2012.

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3.3 Cash from Other Sources

Cash from other sources is projected to total $34.4 million in 2011 and $41.4 million in 2012. Compared to 2010, revenues from other sources are forecast to be $3.3 million higher in 2011 and increase by another $6.9 million in 2012. 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 this other revenue is projected to be $21.8 million in 2011 and $22.2 million in 2012. Descriptions of each of the items that comprise the other revenue category and their forecasted changes are provided below.

Table 3.2
Cash from Other Revenue

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Late Payment Fees	3,622,266	3,706,548	84,282	3,794,205	87,657
Revenue From Damage	1,533,540	1,564,569	31,029	1,596,840	32,271
Other O&M Revenue	6,619,630	5,374,846	(1,244,784)	5,501,958	127,112
Rental Income	1,444,043	1,477,643	33,600	1,512,589	34,946
Transmission Attachments & Cell Sites	2,865,433	2,719,612	(145,821)	2,749,843	30,231
Class 1 Pole Attachments	1,366,381	1,400,339	33,958	1,434,232	33,893
Class 2 Pole Attachments	0	624,054	624,054	639,158	15,104
Account Change Fee	1,448,010	1,455,656	7,646	1,492,047	36,391
Reduced Current Diversion	2,106,000	2,106,000	0	2,106,000	0
Miscellaneous Income	(646,222)	1,384,114	2,030,336	1,415,665	31,551
Total	**$20,359,082**	**$21,813,381**	**$1,454,299**	**$22,242,537**	**$429,156**

- ***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. Late payment fees are expected to increase from $3.6 million in the *2010 Rate Study* to $3.7 million in 2011 and to $3.8 million in 2012

- ***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 due to changes in accounting rules that require greater use of gross accounting for most revenues and expenses. In the *2010 Rate Study* revenue from damage to property and equipment was forecasted to be about $1.5 million. It is projected to increase by about $30,000 annually in 2011 and 2012, reflecting the assumed impact of inflation on repair costs.

- ***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. In 2010 these revenues were forecasted to be $6.6 million. However, they are now being projected to decline to $5.4 million in 2011 and $5.5 million in 2012. Due to budget constraints resulting from the economic recession the Department has scaled back on maintenance. The scope and frequency of Skagit tours are also under review at this time.

- ***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. Property rental income is expected to increase by $30,000 in 2011, compared to the amount in the *2010 Rate Study*, and another $30,000 in 2012, based on the assumption that these rental charges will gradually increase in order to keep pace with inflation. There is additional miscellaneous rental income forecasted to be around $0.2 million in both 2011 and 2012, which is about the same level as it was in the *2010 Rate Study*, rising about $4,000 each year. Total rental income, therefore, is expected to increase approximately $34-$35,000 each year.

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

Revenues from rentals for transmission attachments and cellular sites are forecasted to be $2.7 million in 2011 and $2.8 million in 2012. This is a decrease from $2.9 million forecasted for 2010. The decrease is explained by an expected slow recovery in the local economy.

- ***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 Class 2 attachments are billed at a market-based rate. 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.” Table 3.2 shows revenue collected from both types of attachments, which is forecasted to increase by about $0.7 million in 2011 over the *2010 Rate Study* amount due to the growth in the number of attachments. Revenues are expected to increase with the rate of inflation between 2011 and 2012.

- ***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 2009. These revenues are projected to increase by a little over $7,600 in 2011 over the amount forecasted in the *2010 Rate Study* and by another $36,000 between 2011 and 2012 due to growth in the number of accounts.

- ***Reduced Current Diversion***

These revenues include cash from curbing energy losses caused by electric current diversion and un-permitted house re-wires. Their total is projected to be about $2.1 million in both 2011 and 2012 as in 2010.

- ***Miscellaneous Income***

Miscellaneous income includes income, net of expenses, for non-operating property, as well as construction charges and reconnection fees. The non-operating property expenses include 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 was expected to reimburse this amount in 2010, causing this portion of projected net miscellaneous income to be negative $0.9 million for that year. Currently, this portion of miscellaneous income is forecast to be about $1.1 million in both 2011 and 2012.

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 2011 and $11,000 in 2012.

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 2011 and 2012 are forecasted to remain near the *2010 Rate Study* level of $0.2 million.

Combining these items, therefore, indicates that the total for Miscellaneous Income is expected to increase about $2.0 million in 2011 over the expected amount in the *2010 Rate Study*, then to increase another $30,000 in 2012. The large increase in 2011, as mentioned above, is mostly associated with a prepayment for 2010 streetlight maintenance from the City's Cash Pool.

3.3.2 Investments

City Light's investment income is projected to be $4.4 million, around the same level as in the *2010 Rate Study*. It is then projected to increase by $6.0 million to $10.4 million in 2012. One of the main reasons for the large increase in the investment income between 2011 and 2012 is the difference in the assumed interest rates. The current forecast assumes that interest rates stay low in 2011 and increase in 2012. Investment income also depends on the level of funds in cash balances. These levels, in turn, 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 investment income in 2011 includes interest earned on cash balances in the Rate Stabilization Account (RSA). See Appendix 2 for more detail on the RSA.

3.3.3 Sale of Property

The Department sells surplus real property. Sales of surplus property are projected to be $2.6 million in 2011 and $2.3 million in 2012. These amounts are higher than the 2010 amount because the Department is making an attempt to sell its surplus properties more quickly and at higher prices. The process to sell surplus properties is complicated, and can take upwards of 18 months.

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. The projected amount is $0.7 million for 2011 and $0.9 million for 2012.

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 2010, the Department expected to receive $0.7 million in grants, the majority of which was a grant for toxic cleanup. The current forecast shows that the amount of operating fees and grants is expected to decrease to $0.3 million in 2011 and $0.1 million in 2012. The timing and amount of grants to be received is not often known far enough in advance to make precise forecasts more than a few months ahead of time; therefore, this forecast can change significantly as grants become available.

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 2011 and 2012, which is approximately what City Light has been collecting in previous years. There are currently nine customers paying distribution capacity charges because they requested that City Light reserve the additional capacity.

3.3.7 Green Power Programs

City Light receives revenues from three 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 helps promote 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 third program is a new program called "Community Solar," the mission of which is to promote use of solar energy. This program is currently under development and SCL has received funds from the federal government to help launch it. The projected revenue from voluntary green power programs is about $2.5 million in 2011, an increase of $1.5 million over the 2010 forecast, and $3.1 million in 2012, an increase of $0.6 million over the 2011 forecast. These increases are due to several factors such as people becoming more aware of the Green Power Programs through Seattle City Light marketing efforts, federal sponsorship, general public concern about climate change, and an expectation of a greater public 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. Power factor is measured as a proportion of real power to apparent power and varies in a range from 0.00 to 1.00. When customers' average power factors are below the standard that the Utility has set, the Utility has to provide extra reactive power to compensate for the low power factor, typically by installing capacitors on its system. Power factor charges serve two purposes. First, in the absence of customer-provided correction equipment, this charge compensates the Utility for the installation of the capacitors. Second, this charge encourages customers to install their own capacitors or other corrective equipment.

These charges are projected to slightly decrease to $2.5 million in 2011 as compared to the 2010 forecast and increase by about $0.2 million between 2011 and 2012. 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

City Light base rates include a charge for the cost of transformers to City Light. City Light reimburses customers who provide their own transformers based on kW of demand. Credits for transformation, therefore, reduce the total of Cash from Other Sources. The forecasted expense in 2011 and 2012 is expected to be about the same level as was forecasted for 2010, about $0.3 million.

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. Costs of City Light's ELIA Program, therefore, reduce the total of Cash from Other Sources. For more detailed information about ELIA see Chapter 6. As in the *2010 Rate Study*, the expenses are projected to be around $0.3 million annually.

Chapter 4 - Cash to Power Contracts

4.1 Overview

Table 4.1 presents an overview of costs for purchased power from the *2010 Rate Study* and the 2011-2012 Forecast.

Table 4.1
Purchased Power Contracts

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Bonneville Power Administration	$172,418,816	$165,927,853	($6,490,963)	$163,918,111	($2,009,742)
Wind Resources	21,163,611	21,715,106	551,495	25,215,590	3,500,484
High Ross	13,075,067	13,080,667	5,600	13,088,767	8,100
Lucky Peak	6,065,000	5,966,670	(98,330)	6,189,769	223,099
Grand Coulee	5,014,000	5,123,000	109,000	5,169,000	46,000
Priest Rapids	12,441,250	11,900,000	(541,250)	13,100,000	1,200,000
SPI Purchase	1,716,407	2,421,544	705,137	2,463,817	42,273
Renewable Resource Acquisition	0	3,520,000	3,520,000	7,027,749	3,507,749
Columbia Ridge (*)	2,870,691	2,816,200	(54,491)	2,880,300	64,100
Water for Power	9,340,263	10,485,201	1,144,938	11,028,255	543,054
Wheeling	45,159,602	39,873,009	(5,286,593)	39,210,070	(662,940)
Total Cash to Power Contracts	**$289,264,707**	**$282,829,250**	**($6,435,457)**	**$289,291,427**	**$6,462,177**

(*) Called "IRP Resource" in *2010 Rate Study*

Total costs decline by $6.4 million between what was projected as the average cost for the *2010 Rate Study* and what is now projected for 2011. Purchased power costs are expected to rise by $6.5 million in 2012 returning total purchased power costs in 2012 to nearly the same total as in 2010.

The largest contract cost reductions for 2011 are for Bonneville ($6.5 million) and wheeling ($5.3 million). The majority of the change for Bonneville is an expectation of a substantial Slice credit, rather than an expense. Other reductions in 2011 include Priest Rapids ($0.5 million) and Lucky Peak ($0.1 million). These reductions are offset by increases in costs for other resources, the largest of which is $3.5 million associated with City Light’s Renewable Resource Acquisition Plan. Additionally, fees that must be paid for land and water rights used in production – called Water for Power – are expected to increase by $1.1 million in 2011.

Costs for power resources are expected, in general, to increase in 2012. The largest increases in 2012 compared to 2011 are for wind resources ($3.5 million), renewable resource acquisitions ($3.5 million), and Priest Rapids ($1.2 million). Costs for BPA are expected to decline about $2.0 million and wheeling costs are expected to decline about $0.7 million in 2012. 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 (aMW). 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.

BPA is required by law to give preference to government-owned utilities and to residential customers in the Northwest region in its wholesale power sales. City Light is one of about 130 utility and governmental customers who purchase power from BPA at cost-based wholesale rates.

City Light's Block and Slice Power Sales Agreement with BPA provides for purchases of power 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 aMW annually for the period from October 1, 2001 through September 30, 2006, and 278.2 aMW 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 by which BPA purchases energy savings realized by the Department's conservation programs. The Department's annual entitlement to Block power between September 29, 2009, through the end of this contract on September 30, 2011, is 237.65 aMW.

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, energy available to the Department through the Slice product is expected to average 406 MW under average conditions.

City Light has signed a new contract with BPA that will follow the end of the current contract. The new contract extends to September 30, 2028 and becomes effective October 1, 2011. City Light chose to buy the maximum it was entitled to purchase from BPA but changed the allocation of its purchase so that the amount of energy purchased from the Slice product declined but the purchase from Block increased moderately. In terms of total MWH energy from average or normal water, City Light will receive less energy from BPA under the new contract.

Table 4.2 presents a comparison of the major factors affecting BPA costs as they were projected in the *2010 Rate Study* and as they are now projected for 2011 and 2012. As noted in that table, total costs decline about $6.5 million in calendar year 2011. There is a further decline in total costs in 2012--about $2.0 million. The majority of the decrease in 2011 is associated with a BPA announcement they expected to provide a Slice true-up credit, rather than an expense, for 2010 which will be booked in 2011. City Light's share of the credit is expected to be about $5.1 million, contrasted with the $1 million typical true-up expense. The remaining decrease in BPA expense in 2011 and the decrease in total cost for all of 2012 is associated with a decline in costs for the smaller Slice product in the new contract. There are increases in costs for the enlarged Block product, but those increases are smaller than the declines in the Slice costs.

The decline in basic Slice costs is associated with reductions in the percent of total Slice output that City Light will purchase under the new contract. City Light's annual average share of the Slice product's total output declines about a quarter of a percent in 2011 based on reductions in share in the last three months of the year and declines a further three quarters of a percent in 2012. The associated base costs decline about $4.2 million in 2011 and decline a further $12.7 million in 2012. Changes in the annual Slice true-up costs account for another reduction of $6.1 million in 2011, so that total Slice costs that year decline $10.3 million compared to the *2010 Rate Study*. Slice true-up costs in 2012, though, are expected to be positive at about $0.5 million which amounts to a $5.6 million increase over true-up adjustments in 2011. Thus, total Bonneville costs for 2012 are expected to decline about $7.1 million compared to 2011.

Costs for power from the Block product in 2011 will be $3.8 million higher than the costs forecasted in the *2010 Rate Study*. Block energy in the last three months of 2011, governed by the new contract with BPA, results in an increase in annual energy from the Block product in 2011 of about 20,300 MWh (slightly less than a one percent increase in annual energy) and an increase in annual average rates of $1.54/MWh (about a 5.2 percent increase). Consequently, total Block costs for calendar year 2011 rise about $3.8 million (about a 6.2 percent increase). All of calendar year 2012 is governed by the new contract so that annual energy increases another 122,000 MWh (an increase of 5.8 percent over calendar year 2011) and average rates rise another $0.57/MWh (an increase of 1.8 percent). Total BPA Block costs in 2012, therefore, rise another $5.1 million (an increase of nearly 7.8 percent).

Table 4.2
Bonneville Power Administration

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Slice					
% Ownership (1)	4.6676	4.4149	(0.2527)	3.6566	(0.7582)
Ann. Base Cost	$109,923,380	$105,693,513	($4,229,867)	$93,003,912	($12,689,601)
Ann.True-Up Adjustments	1,000,000	(5,100,000)	(6,100,000)	500,000	5,600,000
Total Slice	**$110,923,380**	**$100,593,513**	**($10,329,867)**	**$93,503,912**	**($7,089,601)**
Block					
MWh	2,081,826	2,102,085	20,259	2,224,462	122,377
Avg. Rate ($/MWh)	$29.54	$31.08	$1.54	$31.65	$0.57
Total Block	**$61,495,436**	**$65,334,340**	**$3,838,904**	**$70,414,198**	**$5,079,859**
Total BPA	**$172,418,816**	**$165,927,853**	**($6,490,963)**	**$163,918,111**	**($2,009,742)**

(1) Prorated for 2011 to reflect contract change

Block costs, and for that matter Slice costs, in future years will change only when BPA again changes the rates charged or there is a change in Block purchases associated with BPA purchases of energy savings realized by the Department's conservation programs.

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 Iberdrola

Renewables (formerly PacifiCorp Power Marketing or PPM). City Light purchases a percentage of the output from the Stateline 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.

Table 4.3 shows both the power cost for Stateline and the costs for the associated integration and exchange contract. In an integration and exchange agreement, one party takes whatever power is produced by another party's generator and then returns it later as a firm constant block. For City Light, the value of this agreement is that it converts volatile, uncertain wind power from Stateline into a known quantity delivered one month later at a local BPA hub. This alleviates the need for additional power marketing staff to manage the real time output of the project, as well as the need for transmission from Stateline, since City Light already has a blanket purchase of transmission services from BPA.

As shown in Table 4.3, a small increase in cost is expected in 2011 compared to the *2010 Rate Study*, even though expected output declines that year. The large increase over 2011 in projected costs for 2012 is due to anticipated changes to the integration and exchange contract terms that increase the MWh covered by the agreement from 150 MW to the full 175 MW capacity of City Light's share of Stateline. The increase in integration costs is partially offset by a reduction in transmission costs, which is discussed later.

Table 4.3
Wind Power Costs

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Wind Resources	$21,163,611	$21,715,106	$551,495	$25,215,590	$3,500,484
MWh	402,844	371,144	(31,700)	372,167	1,023
Power Cost	$15,712,024	$16,293,950	$581,926	$16,293,950	$0
Integration & Exch cost	$5,451,587	$5,421,156	($30,431)	$8,921,640	$3,500,484
$/MWh, Power	$39.00	$43.90	$4.90	$43.78	($0.12)
$/MWh, Int & Exch	$13.53	$14.61	$1.07	$23.97	$9.37
$/MWh, Total	$52.54	$58.51	$5.97	$67.75	$9.24

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 power equivalent to that which would have resulted from an addition to the height of City Light's Ross Dam on the Skagit River that would have expanded the area flooded in British Columbia. 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 costs 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. Table 4.4 presents data from the *2010 Rate Study* and the 2011-2012 Forecast.

Table 4.4
High Ross

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
High Ross	$13,075,067	$13,080,667	$5,600	$13,088,767	$8,100
MWh	310,246	310,246	0	310,246	0
$/MWh	$42.14	$42.16	$0.02	$42.19	$0.03

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 Federal Energy Regulatory Commission (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. 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 BPA 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 years 2010 and 2011. The purchaser (Cargill), in exchange for the actual output, will deliver to City Light at the Mid-Columbia (Mid-C) trading hub 100 MW flat in the heavy load hours (HLH) for each of the months in the first quarter and 50 MW HLH flat for the fourth quarter of the year. Additionally, the purchaser will deliver 100 MW flat in the light load hours (LLH) in the months of January and February.

No sales of Lucky Peak output for 2012 have been arranged yet, so the forecast assumes the output is sold at market rates projected then.

City Light's contract with the Districts calls for City Light to make annual payments for: 1) ownership and maintenance costs, 2) royalty payments to the Districts and 3) debt service payments. Debt service payments ended in June 2008, however; therefore, the 2010-2012 payments to the Districts only include the first two types of payments. Table 4.5 presents the total combined cost for both of these payments in the *2010 Rate Study* and the current 2011-2012 forecast.

Table 4.5
Lucky Peak

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Lucky Peak	$6,065,000	$5,966,676	($98,324)	$6,189,769	$223,093
MWh	292,981	293,347	366	293,622	276
$/MWh	$20.70	$20.34	($0.36)	$21.08	$0.74

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. Total City Light costs are expected to increase by about $0.1 million in 2011 compared to cost projections in the *2010 Rate Study* primarily because of an expected small increase in operating costs. In 2012, a further small increase in operating costs is expected.

Table 4.6

Grand Coulee

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Grand Coulee	$5,014,000	$5,123,000	$109,000	$5,169,000	$46,000
MWh	239,763	240,034	271	240,034	0
$/MWh	$20.91	$21.34	$0.43	$21.53	$0.19

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 relicensing process in recent years with FERC. The original collection of utilities that had purchased output from these two dams was given an opportunity to purchase output again. However, a number of other, previously non-participating, utilities filed petitions in the relicensing process in order to be able to purchase the output from these dams as well.

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 the 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** (for more information see Section 3.1.2 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 *2010 Rate Study* and as now projected for 2011 and 2012. Average price is expected to decline slightly in 2011 and then rise again in 2012. Given an expectation of no change in power from this resource, total costs decline in 2011 by about $0.5 million, then rise $1.2 million in 2012.

The average power costs in Table 4.7.1 are somewhat misleading since all costs are included but are gross of revenue from the Reasonable Portion product, which City Light receives as a cash payment rather than as energy. Nevertheless, the change in costs and power amount shown in the table are used to decompose the change in costs estimated in the *2010 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. Table 4.7.2 shows total costs and average costs, after netting out the revenue from the 'Reasonable Portion' product, for each separate product.

Table 4.7.1
Priest Rapids

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Priest Rapids	$12,441,250	$11,900,000	($541,250)	$13,100,000	$1,200,000
MWh	228,414	173,833	(54,581)	174,921	1,088
$/MWh	$54.47	$68.46	$13.99	$74.89	$6.43

Table 4.7.2
Details of Priest Rapids Cost for 2011 and 2012

	Rate Study 2010	Forecast 2011 (*)	Change 2011 - 2010	Forecast 2012 (*)	Change 2012 - 2011
Priest Rapids, Total Cost	$12,441,250	$11,900,000	($541,250)	$13,100,000	$1,200,000
Conversion Product	370,990	350,065	(20,925)	384,031	33,966
Reasonable Portion	2,971,146	2,803,561	(167,585)	2,999,511	195,950
Surplus Product	517,970	573,795	55,825	0	(573,795)
Meaningful Priority Election	8,581,144	8,186,171	(394,973)	9,733,464	1,547,293
Priest Rapids, Revenue	$8,590,472	$8,200,000	($390,472)	$9,500,000	$1,300,000
Priest Rapids, Net Cost	3,850,778	3,700,000	(150,778)	3,600,000	(100,000)
Total MWh	228,414	173,833	(54,581)	174,921	1,088
$/MWh, Total (Net Cost)	$16.86	$21.28	$4.43	$20.58	($0.70)

(*) Total costs are rounded to nearest $100,000

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 stipulates that City Light:

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

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

(c) Purchases from SMUD all of the new renewable energy and environmental attributes (Green Tags) associated with the Burlington resource in excess of 15 MW, or approximately 3 aMW.

City Light expected to receive 26,280 MWh in 2010. Table 4.8 presents the costs and energy now expected for 2011 and 2012. The average price in the table reflects that the bundled cost of renewable resources (i.e., energy and Green Tags) is generally higher than expected market prices. The Green Tags 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 measures and renewable resources. Subsequently, Washington State enacted Initiative 937 (Chapter 19.285 RCW) that requires utilities to acquire renewable resources. The acquisition of Burlington responds to both of these objectives.

Table 4.8
SPI (Burlington Project)

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
SPI Purchase (Burlington Project)	$1,716,407	$2,421,544	$705,137	$2,463,817	$42,273
MWh	26,280	26,280	0	26,352	72
$/MWh	$65.31	$92.14	$26.83	$93.50	$1.35

4.9 Columbia Ridge Landfill

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

Columbia Ridge produces 6.4 MW of electrical output and City Light purchases the energy in excess of station service and the preparation of the landfill gas, which is about 5.8 aMW annually. City Light receives 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
Columbia Ridge Landfill

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Columbia Ridge (*)	$2,870,691	$2,816,200	($54,491)	$2,880,300	$64,100
MWh	50,633	50,633	(0)	50,772	139
$/MWh, Total	$56.70	$55.62	($1.08)	$56.73	$462.08

(*) Called "IRP Resource" in *2010 Rate Study*

Construction of the facility was completed in 2009, and the first delivery of power to City Light occurred in November 2009. City Light expects to receive 50,633 MWh in 2011. Columbia Ridge meets City Light's resource adequacy requirements, is an eligible renewable resource under I-937 and complies with Washington State's greenhouse gas emissions rules for base load generation.

4.10 Renewable Resource Acquisition

The utility is implementing a gradual ramp-up in its strategy to acquire up to 43 MW of new renewable resources through 2016. City Light's resource acquisition strategy is to add a small baseload renewable resource totaling about 7 aMW every year from 2011 to 2016. This makes steady progress towards meeting the State's I-937 requirements. Specifically, acquisitions in 2011 and 2012 are forecast to begin July 1 of each year. In 2012, two-thirds of the target is met with resources (including the 2011 acquisitions) and the remaining third with Green Tags. Price assumptions for these resources come from responses to the Department's 2009 Request for Proposals (RFP). Table 4.10 indicates the assumptions embedded in the current financial plan.

Table 4.10
Renewable Resource Acquisition Plan

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Renewable Resource Acquisition	$0	$3,520,000	$3,520,000	$7,027,749	$64,100
MWh	0	32,000	32,000	61,000	29,000
$/MWh		$110.00	$110.00	$115.21	$5.21

4.11 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 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 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 (USACE). These OFAs submit detailed costs to FERC and these costs are billed through to the licensees.

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 $1,075,077 in 2008 to $4,085,205 in 2009, a substantial increase. Cost estimates for 2010 represented a continuation of these new higher fees, and the forecast for 2011 and future years anticipates that they will keep growing around 10% annually.

State Department of Ecology fees trend upwards for 2010-2012, representing a continuation of the typical annual fee increases seen since 2008.

Through the Pacific Northwest Coordinating Agreement (PNCA), City Light pays other entities for the benefit of storage of water in reservoirs upstream of City Light's facilities. For example, Boundary operations are enhanced because of reservoir storage at three upriver projects: Albeni Falls (USACE), Kerr (Montana Power), and Hungry Horse (US Bureau of Reclamation).

Table 4.11
Water for Power

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Total Water for Power	$9,340,263	$10,485,201	$1,144,938	$11,028,255	$543,054
FERC Administrative Fees	3,404,767	3,002,422	(402,345)	3,315,048	312,626
WA Dept of Ecology	149,892	152,583	2,691	155,457	2,874
PNCA Storage	1,600,730	1,674,500	73,770	1,794,900	120,400
FERC Land Rents	4,184,874	5,655,696	1,470,822	5,762,849	107,153

4.12 Wheeling

Wheeling is a term that means transporting 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 assumed in the *2010 Rate Study* and the 2011-2012 Forecast. Wheeling costs, in total, have decreased because of reductions in estimates for BPA firm wheeling as well as decreases in wheeling costs for Lucky Peak and Wind Resources.

BPA's wheeling costs declined because the *2010 Rate Study* estimates were based on assumptions that BPA would increase its wheeling rates in 2010 by inflationary factors. BPA decided not to change their wheeling rates in the short term; thus, BPA charges decline compared to forecasts available for the *2010 Rate Study*.

Lucky Peak local wheeling costs are paid to Idaho Power which decreased their rates compared to the rates used for the *2010 Rate Study*.

Wheeling costs for the Wind Resource are also projected to decline. The assumptions in the *2010 Rate Study* were that City Light would buy 80 MW of firm transmission for five months of the year and 105 MW of transmission for seven months. These purchases were considered adequate to carry the actual output of 150 MW of capacity of wind farm output. Then, for the last 25 MW of wind farm capacity purchased by City Light, City Light was assumed to buy 25 MW of non-firm transmission capacity. City Light is assumed to purchase 150 MW of Integration and Exchange services in 2011, so there is no need for firm transmission that year.

In 2011, the need to purchase 25 MW of non-firm transmission services for the last 25 MW of wind capacity will remain. In 2012, there is an assumption that all 175 MW of wind capacity will be processed through an integration and exchange contract so there will be no need to purchase either firm or non-firm transmission that year.

Table 4.12
Wheeling

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
BPA Firm Wheeling	$38,540,025	$35,687,621	($2,852,404)	$36,163,432	$475,811
South Fork Tolt	408,444	429,502	21,058	431,936	2,434
Grand Coulee (Local)	148,078	191,870	43,792	192,280	410
Lucky Peak (Local)	2,243,103	1,809,363	(433,740)	1,854,402	45,039
Wind Resources	2,959,330	1,309,290	(1,650,040)	0	(1,309,290)
Columbia Grid & Other Wheeling	860,622	445,363	(415,259)	568,020	122,657
Total Wheeling	**$45,159,602**	**$39,873,009**	**($5,286,593)**	**$39,210,070**	**($662,940)**

Chapter 5 - Cash to Operations

5.1 Overview

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

Cash to Operations is the largest source of controllable expenses for City Light. In both 2011 and 2012, the cost of providing many base services is projected to rise modestly. In addition, City Light is proposing to adopt new programs and expand existing programs to support the Utility's mission of providing reliable energy and excellent customer service. To help mitigate the rate pressure from these increases in operating costs City Light has also proposed $4.6 million worth of cuts relative to the adopted 2010 budget in both 2011 and 2012.

Table 5.1 shows the projected Cash to Operations in 2011 and 2012, along with the changes from the prior year. City Light estimates 2011 Cash to Operations will increase by $24.4 million or 12.1% from the 2010 value in the *2010 Rate Study*. For 2012 City Light projects that Cash to Operations will decrease by $6.9 million or 3.1% from the forecasted 2011 value, due primarily to decreases in Administration and General costs.

Table 5.1
Summary of Projected Cash to Operations in 2011 and 2012

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Production	$29,409,762	$36,216,425	$6,806,663	$35,792,484	($423,941)
Transmission	9,105,905	9,467,918	$362,013	9,671,721	203,803
Distribution	61,357,875	68,199,039	$6,841,164	68,973,687	774,647
Conservation	9,610,203	11,031,407	$1,421,204	11,572,455	541,048
Customer Accounting	29,409,674	29,999,327	$589,653	30,600,515	601,188
Administration	63,303,776	71,698,989	$8,395,213	63,072,957	(8,626,031)
Total Cash to Operations	**$202,197,195**	**$226,613,105**	**$24,415,910**	**$219,683,819**	**($6,929,286)**

The rest of this chapter will provide detail of the changes in each of the Cash to Operations subcategories. Changes will be itemized in the following categories:

1. Inflation: Assumed at 2% annual increase
2. Budget Reductions: Reductions relative to the 2010 Adopted Budget
3. Budget Issue Papers (BIPs): New or expanded programs, or technical adjustments
4. Other (as needed): Miscellaneous changes

In 2010 City Light cut $9 million dollars of operating expenses in response to lower-than-planned wholesale revenue. To help mitigate the rate increases in 2011 and 2012, $4.6 million of these budget reductions were also included in the 2011 and 2012 budget. These reductions are not considered to be sustainable in the long run and are expected to be restored after 2012.

The financial forecast is itemized by the FERC accounting categories to facilitate comparing the forecast against actual reported financial results. Unfortunately, FERC accounting categories do not necessarily parallel City Light budget categories. Therefore, the forecast of revenue requirements requires assumptions about where certain budget categories will be recorded. In summary, there is not a simple or direct cross-walk between budget categories and forecast/accounting categories.

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) and Pend Oreille River (Boundary). City Light also owns and operates two smaller hydroelectric facilities, South Fork Tolt and Cedar Falls, which are both located 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 forecasted for 2011 increased by $6.8 million or 23.1% from the *2010 Rate Study*. In 2012 projected production expenses decreased by $0.4 million or 1.2% relative to the forecasted amount in 2011. Table 5.2 shows a list of major changes in production costs and Table 5.3 provides the individual BIPs.

Major budget reductions for Production include:

- Reduced consultant contracts
- Reduced travel for regional policy issues and project visits
- Elimination of one management position (Span of Control)

Table 5.2
Changes in Cash to Production

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Production Baseline	$28,951,848	$28,951,848	$0	$28,951,848	$0
Inflation		579,039	579,039	1,169,656	590,617
Budget Reductions		(475,000)	(475,000)	(460,000)	15,000
BIPs		6,015,138	6,015,138	4,009,013	(2,006,125)
Green House Gas Mitigation	457,914	1,145,400	687,486	2,121,967	976,567
Total Production	**$29,409,762**	**$36,216,425**	**$6,806,663**	**$35,792,484**	**($423,941)**

Table 5.3
Production Budget Issue Papers

	2011	2012
FERC License Fees	$508,304	$622,363
Boundary Relicensing Mitigation Measures	90,000	145,000
Power Marketing and Control Center Applications	112,250	112,250
NERC Compliance Embedded FTEs for Business Units	568,184	417,000
Power Marketer 1.0 FTE	122,400	122,400
Slice Customer Interface Application-Phase II	140,000	50,000
Boundary Power House (BPH)-Transformer Maintenance	136,000	120,000
Fleet and Mobile Equipment Staff Increase: 1.0 FTE	60,000	60,000
Generation Facility Maintenance add-back	1,650,000	1,400,000
Restore Funding for Space Rent	250,000	250,000
Generation Support Restoration of FTE Funding	78,000	80,000
Generation Facility Maintenance add-back	2,300,000	630,000
Total Production BIPs	**$6,015,138**	**$4,009,013**

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 City Light's service territory. 2011 transmission expenses are expected to be $9.5 million, which is $0.4 million or 4.0% higher than the amount assumed in the *2010 Rate Study*. This increase primarily reflects rising materials costs for ongoing maintenance of transmission property and equipment, which is projected to grow at a slightly greater rate than that projected for other operating and maintenance categories. In 2012 transmission expenses are expected to be $9.7 million, which is $0.2 million or 2.2% higher than the forecasted 2011 amount. There are no proposed new or expanded O&M programs allocated to transmission in 2011 or 2012.

Table 5.4
Changes in Cash to Transmission

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Transmission Baseline	$9,105,905	$9,105,905	$0	$9,105,905	$0
Inflation		362,014	362,014	565,816	203,802
Total Transmission	**$9,105,905**	**$9,467,919**	**$362,014**	**$9,671,721**	**$203,802**

5.4 Distribution

Distribution expenses include the direct expenses of operating and maintaining substations, power lines, line transformers, poles, service connections, meters, and streetlights. Table 5.5 displays the changes to cash to distribution for 2011 and 2012. City Light projects distribution expenses in 2011 will be $6.8 million or 11.1% above what was projected in the *2010 Rate Study*. The majority of the increase came from new or expanded programs (i.e., BIPs), which are provided in detail in Table 5.6.

Major budget reductions include:

- Delay in wood pole inspection program at the Skagit Facility
- Integrating permitting processes with Department of Planning and Development

In 2012 distribution expenses are projected to increase by $0.8 million or 1.1% from the forecasted 2011 levels. A number of distribution and maintenance and planning program expenses were weighted more heavily in 2011 to help smooth the rate impact between the two years.

Table 5.5
Changes in Cash to Distribution

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Distribution Baseline	$61,357,875	$61,357,875	$0	$61,357,875	$0
Inflation		1,227,164	1,227,164	2,478,872	1,251,708
Budget Reductions		(250,000)	(250,000)	(250,000)	0
BIPs		5,864,000	5,864,000	5,386,940	(477,060)
Total Distribution	**$61,357,875**	**$68,199,039**	**$6,841,164**	**$68,973,687**	**$774,648**

Table 5.6
Distribution Budget Issue Papers

	2011	2012
Restore Vegetation Management Transmission Right of Way	$990,000	$900,000
LAMP and WAMS Baseline Program	2,464,000	1,750,000
Station Transformer Replacement Program	180,000	180,000
TLM & NLM/Loadflow Replacement	100,000	0
Neighborhood Cable Injection/Replacement Program	200,000	200,000
Emergency Command and Control Center	100,000	100,000
Engineering Studies: Transmission Congestion Relief	400,000	0
Vegetation Management-Restore Funds	1,000,000	1,000,000
Energy Management System (EMS) Replacement	-	240,000
Distribution System Planning Work	430,000	1,016,940
Total Distribution BIPs	**$5,864,000**	**$5,386,940**

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 service 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 17 for deferred conservation expenditures). Table 5.7 shows that City Light projects that direct 2011 conservation expenses will increase by $1.4 million or 14.8% from the level planned in the *2010 Rate Study*. Forecasted 2012 direct conservation expenses are expected to increase by $0.5 million or 4.9%. The conservation BIP provides funding for the accelerated conservation program identified in City Light's *2008 Conservation 5-Year Plan*.

Table 5.7
Changes in Cash to Conservation

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Conservation Baseline	$9,610,203	$9,610,203	$0	$9,610,203	0
Inflation		192,204	192,204	388,252	196,048
BIPs		1,229,000	1,229,000	1,574,000	345,000
Total Conservation	**$9,610,203**	**$11,031,407**	**$1,421,204**	**$11,572,455**	**$541,048**

5.6 Customer Accounting

Customer accounting expenses include the expenses for reading meters, billing customers, providing information to customers, and maintaining customer records. As shown in Table 5.8, City Light projects 2011 customer accounting expenses will increase by $0.6 million, or 2% from the value in the *2010 Rate Study*. In 2012 it is expected to increase by another $0.6 million, or 2% relative to 2011. The increase is attributed solely to inflation, as there are no budget reductions or BIPs allocated to customer accounting.

Table 5.8
Changes in Cash to Customer Accounting

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Customer Accounting Baseline	$29,409,674	$29,409,674	$0	$29,409,674	
Inflation		589,653	589,653	1,190,841	601,188
Total Customer Accounting	**$29,409,674**	**$29,999,327**	**$589,653**	**$30,600,515**	**$601,188**

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 Department of Executive Administration, injury and damage claims, cleanup of toxic materials, and research and development. Table 5.9 presents the changes to A&G expected in 2011 and 2012. City Light forecasts 2011 A&G cash expenses will increase by $8.4 million or 13.3% from the *2010 Rate Study*. However, 2012 A&G expenses are projected to decrease by $8.6 million or 12.0% relative to 2011 as a result of a significant decrease in BIPs.

Table 5.10 shows the individual A&G BIPs. A&G BIPs are separated into regular BIPs and technical adjustment BIPs in order to differentiate discretionary budget additions from non-discretionary ones.

Major budget changes include:

- Delayed funding for environmental remediation work
- Delayed software replacement
- Reduced bond maintenance and audit costs

- Eliminate funding for one National Urban Fellow
- Prepayment of software maintenance costs in 2011 contribute to increase in that year, and corresponding decrease in 2012

Payments for toxic cleanup (net of accruals) are projected to increase by $2.5 million in 2011 but then decrease by $4.1 million in 2012. These are payments for environmental remediation in a number of different areas including areas around the Cedar and the Duwamish rivers. Some toxic cleanup expenses that were originally projected to be in 2012 were shifted forward into 2011 to help smooth the rate increases between the two years. In addition, a number of A&G BIPs were front loaded in 2011, particularly in IT, to help smooth the rate impact over the two years.

Table 5.9
Changes in Cash to Administration and General

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
A&G Baseline	$60,226,464	$60,226,464	$0	$60,226,464	$0
Inflation		1,166,202	1,166,202	2,433,149	1,266,947
Budget Reductions		(3,862,500)	(3,862,500)	(3,862,500)	0
BIPs		5,725,991	5,725,991	(2,080,833)	(7,806,824)
Techical Adjustment (BIPs)		2,855,000	2,855,000	4,867,800	2,012,800
Toxic Cleanup, Net of Accruals	3,077,312	5,587,832	2,510,520	1,488,877	(4,098,955)
Total A&G	**$63,303,776**	**$71,698,989**	**$8,395,213**	**$63,072,957**	**($8,626,032)**

Table 5.10
A&G Budget Issue Papers

	2011	2012
Software and Contract Maintenance and Support - IT Applications	$1,095,242	$0
Software License/Maintenance for Oracle and Microsoft Products	1,847,916	0
EMS Compliance Improvements	207,000	0
Software and Hardware Maintenance Base Moved to 2011	2,175,833	(2,175,833)
Restoration of Talent Acquisition NERC Compliance	40,000	40,000
Wholesale Energy Risk Policy Review	85,000	55,000
Sustain and Study Replacement of CCSS	275,000	0
Subtotal A&G BIPs	**$5,725,991**	**($2,080,833)**
Techical Adjustment BIPs		
DoIT/SPU Allocation Funding	$1,640,000	$1,652,800
COLA reductions from assumed 2%	(1,400,000)	(1,400,000)
Increase in Pension Contributions	2,500,000	4,500,000
Grant Funded Finance/Conservation Position	115,000	115,000
Subtotal Technical Adjustments	**$2,855,000**	**$4,867,800**
Total All A&G BIPs	**$8,580,991**	**$2,786,967**

Chapter 6 - Cash to Rate Discounts

6.1 Cash to Rate Discounts

City Light 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 amounts to about a 60 percent discount on utility bills. If customers do not have bills in their names (e.g., they live in subsidized housing), 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 expected to increase from 13,830 forecasted in the *2010 Rate Study* to 14,030 in 2011 and to 14,232 in 2012. The energy delivered to Assisted Residential Customers is projected to increase slightly during the 2011-2012 period. Cash to Rate Discounts is expected to increase by about $0.1 million in 2011 as compared to 2010 and by another $0.5 million between 2011 and 2012. This increase is a result of expected increases in retail rates in 2011 and 2012. Low-income customers will receive 40% of this rate increase.

Table 6.1
Cash to Rate Discounts

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Cash from Assisted Residential Customers ($)					
Before Discounts	$10,785,251	$11,196,032	$410,781	$11,945,887	$749,855
After Discounts	4,320,713	4,614,584	293,871	4,881,272	266,689
Cash to Rate Discounts	**$6,464,538**	**$6,581,448**	**$116,910**	**$7,064,615**	**$483,167**
Average Assisted Residential Rate ($/MWh)					
Before Discounts	$75.57	$78.05	$2.48	$82.51	$4.46
After Discounts	$30.28	$32.17	$1.89	$33.72	$1.55
Discount	$45.30	$45.88	$0.58	$48.80	$2.91
Percent Discount	60%	60%	0%	60%	0%
Energy Delivered to Assisted Residential Customers (MWh)	142,711	143,443	0.51%	144,776	0.93%
Number of Assisted Residential Customers	13,830	14,030	1.45%	14,232	1.44%

6.2 Other Low-Income Assistance Programs

The following sections describe other miscellaneous assistance programs for low-income City Light customers. These programs are not part of Cash to Rate Discounts, and instead are grouped with other rate components. Cash to these programs is itemized in Table 6.2 below.

Table 6.2
Other Low Income Assistance Programs

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Waivers of Trouble Call Charges	$1,154	$1,184	$30	$1,214	$30
Waivers of Account Change Fees	37,121	37,327	206	38,260	933
Emergency Low Income Assistance	266,502	272,805	6,303	279,258	6,453
Administration of Low Income Assistance Programs	475,585	486,556	10,971	497,489	10,933

6.2.1 Cash to Trouble Call and Account Change 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 amount to about $38,500 in 2011 and about $39,500 in 2012. Account change fee waivers are part of Cash from Other Sources, a subset of Cash from All Other Sources described in Chapter 3. Trouble call fee waivers are included in Cash to Operations described in Chapter 5.

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 $266,502 projected in the *2010 Rate Study* to $272,805 in 2011 and to $279,258 in 2012. In 2011 and 2012, the forecast is for small increases in customers requesting emergency assistance. 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. These programs are the Utility Discount Program and Project Share. Cash to Administration of Low-Income Assistance Programs is expected to increase from $475,585 projected in the *2010 Rate Study* to $486,556 in 2011 and $497,489 in 2012. The number of customers on rate assistance in 2011 and 2012 is forecast to have a small increase in both years. 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 is never received, despite collection efforts, and must be written off as uncollectable. Uncollectable revenue has been lower in the past three years than it was during several preceding 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 around 0.9% of revenue from energy sales to retail customers, its average level of the past three years. Although this amount may also include some uncollectable wholesale revenue, it is not forecast separately because it is highly variable and usually only accounts for a small proportion of total uncollectable revenue. Total uncollectable revenue is projected to be $6.0 million in 2011 and $6.3 million in 2012.

Chapter 8 - Cash to 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 11, 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 projected in the *2010 Rate Study* and as now projected for 2011 and 2012. 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 State Taxes and Franchise Payments.

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 lower part of Table 8.1 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 2011 and 2012 and what was expected for 2010 in the *2010 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. State taxes also include some very minor ‘Other’ taxes. Overall, revenue taxes account for the vast majority of State and City tax payments and the primary reason for their increase. Business and Other State and City taxes account for only a little over $0.1 million annually and are relatively steady, growing very slowly over time.

Table 8.1
Taxes

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
State Business Tax	$110,574	$114,997	$4,423	$119,482	$4,485
State Public Utility Tax	23,985,349	25,776,768	1,791,419	26,908,416	1,131,647
Other State Taxes	5,225	5,434	209	5,646	212
State Taxes	**$24,101,148**	**$25,897,199**	**$1,796,051**	**$27,033,544**	**$1,136,344**
King County Surface Water Management Fees	144,377	144,377	0	144,377	0
Whatcom County Contract Pmts	916,443	937,679	21,236	959,407	21,728
Pend Oreille County Contract Pmts	1,383,783	1,563,485	179,702	1,608,078	44,593
Renton Business Tax	92	96	4	100	4
Payments to Concrete School District	117,482	120,522	3,040	123,472	2,950
Payments to Other Government Entities	**$2,562,177**	**$2,766,159**	**$203,982**	**$2,835,434**	**$69,275**
Shoreline	1,650,270	1,688,341	38,071	1,726,277	37,936
Burien	762,702	782,532	19,830	802,096	19,564
Lake Forest Park	267,650	274,609	6,959	281,474	6,865
Tukwila	1,720,254	1,764,981	44,727	1,809,105	44,124
SeaTac	132,593	136,040	3,447	139,441	3,401
Payments to Franchises	**$4,533,469**	**$4,646,503**	**$113,034**	**$4,758,393**	**$111,890**
Total State Taxes and Franchise Payments	**$31,196,794**	**$33,309,861**	**$2,113,067**	**$34,627,371**	**$1,317,509**
City Business Tax	11,845	12,319	474	12,799	480
City Occupation Tax	38,541,318	41,419,894	2,878,576	43,238,303	1,818,409
Seattle City Taxes	**$38,553,163**	**$41,432,213**	**$2,879,050**	**$43,251,102**	**$1,818,889**
Factors Affecting City Occupation and State Public Utility Taxes					
% Revenue Deductible from City Tax	2.50%	2.50%	0.00%	2.50%	0.00%
% Revenue Deductible from State Tax	6.00%	6.00%	0.00%	6.00%	0.00%
City Revenue Tax Rate %	6.00%	6.00%	0.00%	6.00%	0.00%
State Revenue Tax Rate %	3.87%	3.87%	0.00%	3.87%	0.00%
Revenue Tax Base	$658,825,944	$708,032,371	$38,259,475	$739,116,293	$28,346,157
Seattle System Load, MWh	9,919,004	10,013,905	94,901	10,188,947	175,042
Average Revenue Tax Base Rate, $/MWh (with CIAC)	$66.42	$70.70	$4.28	$72.54	$1.84

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.

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 *2010 Rate Study* and what is projected now for 2011 and 2012.

8.3 Other Related Expenses

Payments to Counties and Schools. Contract payments 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. The Whatcom County Impact Payment Agreement that has been negotiated stipulates an annual escalator of 2.3171736%. In September 2010, the Department and Pend Oreille County reached agreement on impact payments related to Boundary dam for 2010-2019. The amounts projected for 2011 and 2012, displayed above in Table 8.1, are the agreed-upon amounts per that settlement. Payments to King County for surface water management fees are not projected to increase.

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 Projects.

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 total revenue as of April 2009.

Payments to suburban cities consistent with the franchises are projected to increase from $4.5 million in 2010 to around $4.6 million in 2011 and $4.8 million in 2012. Payments to the suburban cities increase when retail rates increase.

Chapter 9 - Cash to (from) the Rate Stabilization Account

9.1 Overview

In March 2010 the Seattle City Council adopted legislation to create a $100 million Rate Stabilization Account (RSA). The account will provide funds when actual net wholesale revenue is below planned levels. If funds are withdrawn from the RSA they will be replenished with an automatic retail rate surcharge or transfers from operating cash. In addition, any surplus net wholesale revenues above the planned levels will be placed in the RSA. Appendix 2 contains more information on the mechanics of the RSA. The fund will become active January 1, 2011 but is not anticipated to be fully funded until mid 2011.

9.2 Funding Sources

To initially fund the RSA, City Light has proposed a combination of rate surcharges, the existing $25 million contingency reserve, and bond refinancing savings (which are regarded as transfers from the operating cash account). Table 9.1 provides a breakdown of the proposed funding. The reason the RSA account is projected to be over its targeted $100 million dollars at the end of 2011 is due to interest earned on the account after it reaches its targeted amount.

Table 9.1
Proposed Funding Sources for RSA

	2010	2011
Existing Contingency Reserve	$25.0	$0.0
Rate Surcharge Revenue, net	16.0	10.6
Transfers from Operations	27.7	21.0
Interest Income	0.2	0.9
End of the Year Balance	**$68.9**	**$101.4**

9.3 Impacts on Revenue Requirements

Cash that is transferred to the RSA must be accounted for as deferred revenue[5]. This is because funds that are transferred from the RSA to the operating account (to supplement lower than planned net wholesale revenue) will be counted as current year revenue available for debt service coverage. Funds cannot be counted as revenue twice. Therefore, to ensure that funds transferred from the RSA will be available for coverage when they are withdrawn, they will be deferred and not counted in the calculation of debt service coverage in the year in which they are transferred.

Table 9.2 shows the cash transfers to and from the RSA and the resulting impacts on the revenue requirements. Since the RSA did not exist at the time the *2010 Rate Study* was conducted, there are no values in any of the RSA lines for this period. City Light projects that (on an expected

[5] The existing $25 million contingency reserve is an exception to this; these funds are not deferred revenue.

basis) the initial funding of the RSA will increase 2011 revenue requirements by $20.3 million in 2011 but have no impact in 2012.

Table 9.2
Cash to (from) the Rate Stabilization Account

Note		Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
	Cash from Revenues					
[1]	Cash from RSA Surcharge Revenue	$0	$11,716,340	$11,716,340	$0	-$11,716,340
[2]	Interest on RSA Balance	0	927,256		2,941,594	2,014,338
	Cash to Expenses					
[3]	RSA Surcharge Revenue Net of Taxes	0	10,559,586	10,559,586	0	-10,559,586
[4]	Other Operating Cash to RSA	0	20,989,795	20,989,795	0	-20,989,795
[5]	Interest Earned on RSA Balance	0	927,256	927,256	2,941,594	2,014,338
[6]	Total Cash Transferred to RSA Account	0	32,476,637	32,476,637	2,941,594	-29,535,043
[7]	State Taxes on RSA Surcharge	0	453,774	453,774	0	-453,774
[8]	**Net Impact on Revenue Requirements**	**$0**	**$20,286,815**	**$20,286,815**	**$0**	**-$20,286,815**
[9]	City Taxes on RSA Surcharge	0	702,980	702,980	0	-702,980

Cash from Revenues

1. Cash from RSA Surcharge Revenue
   In 2011 City Light projects that it will receive $11.7 million from RSA surcharges. This includes a 4.5% surcharge in the first quarter and a 3% surcharge in the second quarter. Appendix 2 provides more information on how and when surcharges are applied. In 2012 the RSA is expected to be fully funded and (on an expected basis) is not projected to decrease due to lower than planned wholesale revenue. Thus, there is no projected rate surcharge in 2012.

2. Interest Earned on RSA Balance
   Like most cash accounts, the balance of the RSA account earns interest. The interest earned on the RSA account is embedded in the amount in the total interest line in the Cash Flow Table.

Cash to Expenses

3. RSA Surcharge Revenue Net of Taxes
   RSA surcharge revenue net of taxes is the amount of RSA surcharge revenue that is transferred to the RSA. City Light must pay taxes on all retail revenue including revenue received from the RSA surcharge. Therefore, to cover the increased taxes from the RSA surcharge revenue, City light will only transfer the RSA surcharge net of the associated taxes. In 2011 City Light projects that it will transfer $10.6 million from RSA surcharge revenue to the RSA.

4. Other Operating Cash to RSA
   This line includes any transfers from the operating fund to the RSA in addition to RSA surcharge revenue and interest income. As stated above, City Light plans on using some of the savings from the 2010 bond refinancing to establish the RSA. In 2011 City Light

projects that it will use $21.0 million of its bond refinancing savings to fund the RSA. There are no projected transfers from operations in 2012.

5. Interest Earned on RSA Balance
   By City Ordinance, interest earned on the RSA account balance stays in the RSA account. All City Light earned interest is recognized as current year revenue and then allocated to a particular cash account. However, as discussed above, all RSA transfers must be deferred. The full amount of RSA interest income revenue is transferred to the RSA account and deferred.

6. Total Cash Transferred to the RSA Account
   This is the total amount of cash that is transferred to the RSA account. The amount is treated as deferred revenue and will be available to cover debt service requirements in the year it is withdrawn. In 2011 the total cash transferred to the RSA is projected to be $32.5 million, the same amount as shown in the Cash Flow Table.

7. State Taxes on RSA Surcharge
   City Light must pay State and City taxes on the RSA surcharge revenue. State taxes are deducted from the amount available for coverage but City taxes are not. Therefore, in Table 9.2 State taxes are included in the impact on revenue requirements and City taxes are not. In 2011 State taxes on RSA surcharge revenue are projected to be $0.5 million (reflective of a 3.87% State tax rate).

Net Impact on Revenue Requirements

8. Net Impact on Revenue Requirements
   This is equal to the total Cash to Expenses less Cash to Revenues shown in Table 9.2. In 2011 the net impact on revenue requirements is projected to be $20.2 million. This is primarily from the initial funding of the RSA from other operating cash. The small difference is attributed to the fact that city taxes on revenue are not counted against the amount available for debt service coverage.

City Taxes

9. City Taxes
   In 2011 City taxes on RSA surcharge revenue are expected to be $0.7 million (reflective of a 6.0% City tax rate).

Chapter 10 - 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. It is the sum total of all the lines described in the preceding nine chapters, and the bottom line of the cash flow table used to determine revenue requirements. Cash Available for Debt Service Coverage is also equal to debt service multiplied by 1.8, because the retail revenue amount is sized such that this is true.

Table 10.1 confirms the explanation above. Cash Available for Debt Service Coverage must equal cash required for debt service multiplied by the required coverage ratio. Then, the required retail power sales revenue must equal expenses, which exclude City taxes but include cash to the Rate Stabilization Account for 2010 and 2011, less other revenues plus the cash required for debt service coverage. As shown in Table 10.1, compared to the *2010 Rate Study*, Cash Available for Debt Service Coverage is expected to decline by $13.7 million in 2011 because debt service is lower due to the May 2010 bond refunding. Cash available for debt service coverage is projected to increase by $54.8 million from 2011 to 2012. As explained in Chapter 13, only minimal refunding savings were included in the May 2010 bond issue after 2011.

Table 10.1
Cash Available for Debt Service Coverage
$ millions

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Retail Power Sales before Discount	$614.8	$651.5	$36.7	$699.2	$47.7
Other Revenues	190.4	160.6	(29.8)	169.3	8.8
Total Revenues	805.2	812.1	6.9	868.6	56.5
Subtract Expenses	534.7	555.3	20.6	556.9	1.7
Cash Available for Debt Service Coverage	**$270.5**	**$256.8**	**($13.7)**	**$311.6**	**$54.8**
Debt Service	150.7	142.7	(8.0)	173.1	30.5
Debt Service Coverage Target (Ratio)	1.8	1.8	0.0	1.8	0.0
Debt Service * Target DSC	**$270.5**	**$256.8**	**($13.7)**	**$311.6**	**$54.8**

Chapter 11 - Cash to City Taxes

City Taxes were first discussed in Chapter 8 which presented the data on City taxes, along with the other taxes and related costs, as estimated in the *2010 Rate Study* and 2011-2012 forecast. 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.

Utilities are among 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 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 the 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.

Table 11.1 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 *2010 Rate Study* and what is now projected for 2011 and 2012. It also explained that the anticipated increase in taxes in 2011 and 2012 is primarily attributable to the projected increase in retail rates and, hence, increase in the retail tax base in those years.

Table 11.1
Cash to City Taxes

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
City Business Tax	$11,845	$12,319	$474	$12,799	$480
City Occupation Tax	38,541,318	41,419,894	2,878,576	43,238,303	1,818,409
Cash to City Taxes	**$38,553,163**	**$41,432,213**	**$2,879,050**	**$43,251,102**	**$1,818,889**

Chapter 12 - Cash to All Other Purposes

Cash to All Other Purposes includes cash adjustments that do not directly affect revenue requirements. These cash adjustments are for changes in balance sheet accounts which have not already been counted as revenue or expenses in that year. Cash to All Other Purposes includes changes in the balances of materials and supplies, unbilled revenue and retail revenue accounts receivable. Table 12.1 illustrates these other uses of cash for the period 2010 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 12.1
Cash to All Other Purposes

	Rate Study 2010	Forecast 2011	Change 2011-2010	Forecast 2012	Change 2012-2011
Materials and Supplies	$621,482	$0	($621,482)	$0	$0
Unbilled Revenue	5,264,476	$1,256,027	(4,008,449)	$1,620,759	364,731
Accounts Receivable (Retail Revenue)	(2,377,142)	($541,058)	1,836,084	($447,126)	93,932
Total Cash to All Other Purposes	**$3,508,816**	**$714,969**	**($2,793,847)**	**$1,173,633**	**$458,663**

Cash to Material and Supplies
Cash to Material and Supplies is the change in the Materials and Supplies balance sheet accounts. It is the change in the level of materials and supplies stored in warehouses. These materials and supplies are waiting to be used in capital and maintenance projects. The materials have been purchased but have not been recorded as either capital or operating expenses and, therefore, must be recorded as a use or source of cash elsewhere. The current forecast assumes a zero change in the balance of materials and supplies accounts during both 2011 and 2012. The *2010 Rate Study* assumed an increase in materials and supplies of around $0.6 million.

Cash to Unbilled Revenue and Cash to Accounts Receivable (Retail Revenue)
As stated in Chapter 1, 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. Therefore an adjustment must be made that estimates the actual cash received from retail sales in any particular year.

Cash to Unbilled Revenue and Cash to Accounts Receivable (Retail Revenue) are adjustments used to turn earned retail revenue into retail cash collected for a particular year. The annual cash adjustment is the change in the balance of the respective balance sheet account. Unbilled Revenue is revenue earned from energy that has already been consumed by customers but not yet billed to them. Increases in this balance result in positive Cash to Unbilled Revenue. The Accounts Receivable (Retail Revenue) balance is revenue that has been billed to retail customers but not yet received from them. Increases in this balance are called Cash to Accounts Receivable (Retail Revenue). Both cash flows are affected by changes in customer load and retail rates. Cash to Unbilled Revenue is projected to be positive in 2011 and 2012 but lower than in 2010. The balance of Cash to Accounts Receivable is projected to decline in both 2011 and 2012, but show less of a decline than in 2010.

Chapter 13 - Cash to Debt Service

Cash to Debt Service is the sum of principal and interest payments on outstanding debt. City Light's financial policies require it to set rates so that it will expect to have cash available to cover its debt service 1.8 times after all required operating expenses are paid. Table 13.1 shows the changes in debt service projections for 2011 and 2012 along with the changes from the prior year. The forecasted debt service in 2011 is projected to be $8.0 million below the 2010 value in the *2010 Rate Study*. The forecasted debt service in 2012 is expected to exceed the 2011 value by roughly $30.5 million.

Table 13.1
Change in Cash to Debt Service

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Cash to Debt Service	$150,693,139	$142,658,754	($8,034,385)	$173,113,109	$30,454,355

Table 13.2 provides information on the projected future bond issues and also breaks out debt service by principal and interest payments. City Light projects that it will be issuing $210 million in debt in March of 2011 and $200 million in March of 2012. These are the estimated amounts required to keep the operating cash balance above $50 million, which is City Light's targeted minimum cash balance. The assumed principal repayment schedule on forecasted debt issues follows a flat annual schedule, with interest payments twice a year.

Table 13.2
Cash to Debt Service Detail

	Rate Study 2010	Forecast 2011	Forecast 2012
Cash from the Sales of Bonds	$200,000,000	$210,000,000	$200,000,000
Cash to Bond Issue Costs	1,643,811	1,260,000	1,200,000
Interest Rate on Bonds Sold	4.80%	5.0%	5.0%
Issue Month	DEC	MARCH	MARCH
Bonds Sold before Jan 1, 2011	$69,958,139	$78,723,754	$69,509,441
Bonds Sold after Jan 1, 2011 (projected)	-	5,250,000	15,337,089
Cash to Interest Payments	**$69,958,139**	**$83,973,754**	**$84,846,530**
Bonds Sold before Jan 1, 2011	80,735,000	58,685,000	83,865,000
Bonds Sold after Jan 1, 2011 (projected)	-	(0)	4,401,579
Cash to Principal Payments	**$80,735,000**	**$58,685,000**	**$88,266,579**
Bonds Sold before Jan 1, 2011	150,693,139	137,408,754	153,374,441
Bonds Sold after Jan 1, 2011 (projected)	-	5,250,000	19,738,668
Cash to Debt Service	**$150,693,139**	**$142,658,754**	**$173,113,109**

In May of 2010 City Light sold approximately $792 million in bonds,[6] of which approximately $595 million was used to refinance existing debt. This total amount was divided into a number

[6] SCL received a premium of around $62 million, providing cash proceeds of approximately $855 million.

of bonds with different maturity dates. In order to assist in providing capital to the new Rate Stabilization Account in the near term, relatively fewer bonds had near term maturation dates. This fact, combined with realizing lower interest rates, allowed the savings on the refinancing to be front loaded in 2010 and 2011. The 2010 and 2011 savings were around $32 million and $22 million, respectively. In addition to the refinancing, around $255 million of the 2010 bond issue was for new money to help fund City Light's Capital Improvement Program.

The adopted *2010 Rate Study* assumed that the 2010 debt issue would be $200 million and have the principal and interest deferred for one year. However, the 2010 Bond Issue actually included about $255 million of new money and the Department did not defer the principal and interest payments, which partially helps explain the difference in the projected debt service between the *2010 Rate Study* and *2011-2012 Rate Study*.

The primary reasons for the $8.0 million difference between the forecasted 2011 and adopted 2010 debt service are:

- Refinancing savings in 2011 from 2010 bond issue
  - Lower interest rates and less principal retired in 2011 on the 2010 bond issue
- Partially offset by higher debt service on the "new money" portion of the 2010 bond issue
  - The debt service on the 2010 bond issue is higher in 2011 than what was assumed for 2010 in the *2010 Rate Study*
- Partially offset by higher debt service on the 2011 bond issue

The primary reasons for the $30.5 million difference between the forecasted 2012 and forecasted 2011 debt service include:

- Less refinancing savings from 2010 bond issue
- Principal payment and one additional interest payment on the 2011 bond issue.
- Interest payment on the 2012 bond issue

Chapter 14 - 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 expenditures for the Capital Improvement Program (CIP), deferred conservation expense and deferred environmental mitigation expense. The higher the amount of Cash from Operations available for capital expenditures, the lower the amount the utility needs to borrow to fund capital expenditures by issuing long-term debt. City Light projects that Cash from Operations will be $72.0 million in 2011 and $94.1 million in 2012.

Chapter 15 - Cash from Contributions

15.1 Overview

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 costs 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. That is, the larger capital expenditures, the larger City Light would expect these funding sources to be.

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 15.1 displays the 2010-2012 forecast of funding from contributions, grants and fees, breaking it into the major categories, which are further described below.

Table 15.1
Cash from Contributions

	Rate Study 2010	Forecast 2011	Forecast 2012
Contributions in Aid of Construction	$26,594,243	$24,660,093	$18,970,023
Grants from Sound Transit	713,114	2,119,000	381,000
Other Capital Fees and Grants	120,717	96,000	101,000
BPA Funding for Conservation	2,300,000	4,732,690	-
Total Cash from Contributions	**$29,728,074**	**$31,607,783**	**$19,452,023**

15.2 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 to enhance reliability. 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 the total CIAC to decrease during the 2011-2012 period. Major categories of CIAC-reimbursed capital expenditures in 2010-2012 are itemized in Table 15.2.

Table 15.2
Contributions in Aid of Construction

	Rate Study 2010	2011	2012
Transmission	$1,371,433	$1,266,187	$1,289,686
Cedar Falls Switchyard Expansion and Line Extension	3,613,465	1,436,489	14,330
Distribution Capacity Additions	2,096,023	1,339,201	1,720,024
Network Additions and Services	3,770,480	1,978,255	1,882,147
Overhead and Underground Services	6,781,673	7,434,216	7,751,316
Transportation Driven Relocations	2,457,223	3,428,548	3,465,733
Streetlights	3,172,616	1,070,671	1,070,686
Creston-Nelson to Intergate East Feeder Installation	3,083,114	1,962,309	139,522
First HIll Connector Streetcar Engineering	115,917	2,048,953	134,383
Pole Attachment Requests Preparation Work	-	1,356,811	1,484,115
SeaTac Undergrounding		1,310,457	-
Other	132,299	27,997	18,080
Total Contributions in Aid of Construction	**$26,594,243**	**$24,660,093**	**$18,970,023**

15.3 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. However, the utility does not expect to be reimbursed for the cost of relocating electrical equipment before and after construction of the Alaskan Way Viaduct; 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 $28.0 million in grant funding for this work. As Table 15.1 shows, City Light expected to receive another $0.7 million in 2010. The actual amount will be available when books for 2010 are closed. Another $2.1 million is anticipated in 2011 and $0.4 million in 2012.

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 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 average about $0.1 million annually in 2010-2012.

15.4 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 15.1. Conservation projects started during BPA fiscal years 2007-2011 are being funded pursuant to a "Conservation Acquisition Agreement." Under this 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.

Chapter 16 - Cash from Bond Proceeds

Cash from Bond Proceeds is not available to pay debt service costs and, therefore, does not affect the 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 2010 to 2012 is shown in the bottom section of Table 16.1 as the Cash from the Bond Proceeds Account. This amount is equal to Cash to Capital Expenditures minus Cash from Operations and Contributions. Cash from Bond Proceeds is the projected amount of bond proceeds used for capital expenditures. Capital expenditures referenced here are the total expenditures for capital, deferred conservation, and deferred O&M.

Cash to the Bond Proceeds Account is the projected amount of bond proceeds received. This amount is shown in the top section of Table 16.1. City Light projects that it will sell $210 million in bonds in 2011 and $200 million in bonds in 2012. The 2011 million bond issue is forecast to be $10 million larger than the 2012 bond issue in order to provide $10 million funding for a bond reserve account. The assumed debt issue cost percentage is 0.6%, which results in a cash to bond proceeds amount of $198.7 million in 2011 and $198.8 million in 2012.

2010 bond proceeds described in this chapter and displayed in Table 16.1 do not include proceeds of the 2010 bond issue used to refund existing debt because they do not directly affect the amount of cash used to fund capital expenditures. They do have a direct impact upon revenue requirements, however, by reducing debt service in 2011, 2012 and all future years.

Table 16.1
Cash to and from Bond Proceeds Account

	Rate Study 2010	Forecast 2011	Forecast 2012
Cash from the Sale of Bonds	$258,277,821	$210,000,000	$200,000,000
Minus Cash to Bond Issue Costs	3,766,877	1,260,000	1,200,000
Minus Cash to the Bond Reserve Fund	0	10,000,000	0
Cash to the Bond Proceeds Account	**$254,510,944**	**$198,740,000**	**$198,800,000**
Cash to Capital Expenditures	226,186,667	292,005,508	326,250,789
Minus Cash from Operations	22,067,389	71,990,879	94,071,752
Minus Cash from Contributions	29,183,214	31,607,783	19,452,023
Cash from the Bond Proceeds Account	**$174,936,064**	**$188,406,846**	**$212,727,014**

Chapter 17 - Cash to Capital, Conservation and Deferred O&M

17.1 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 to comply with regulatory environmental and mitigation requirements. The following investments support these goals:

- To improve City Light's energy delivery infrastructure, City Light is proposing investment in asset management and business process re-engineering, targeted steps towards a Smart Grid, communications within the utility and with customers, security and emergency preparedness, and other improvements in core utility infrastructure which enable 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 the Department's organizational performance, 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 own 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 and activities associated with relicensing City Light dams. 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 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.

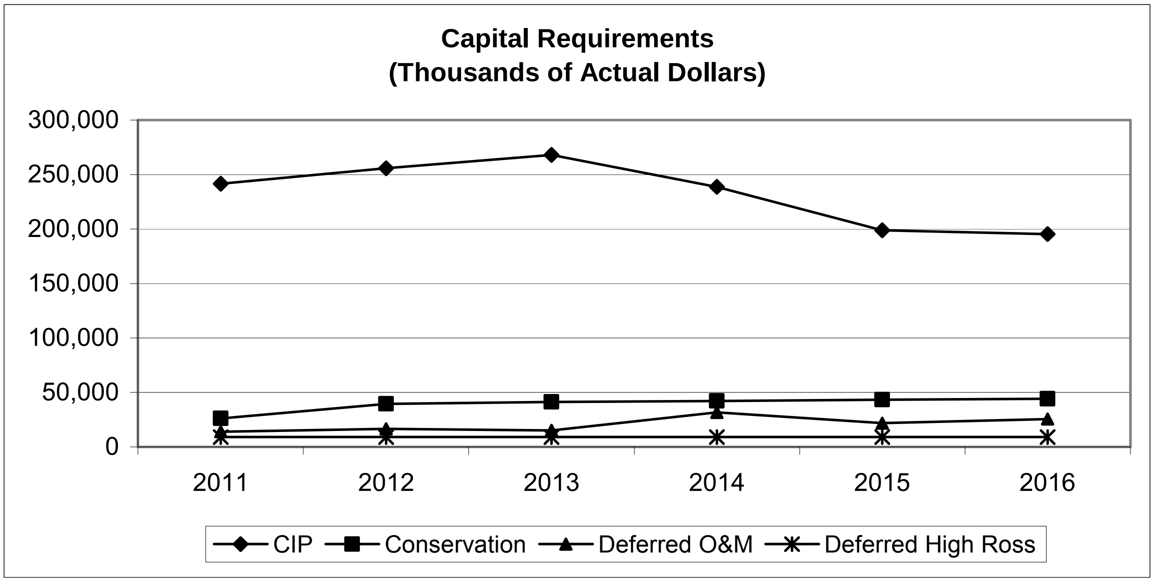
Sections 17.2 and 17.3 present information on capital expenditures and the CIP forecast. Deferred conservation expenditures are reviewed in Section 17.4 and other deferred costs in Sections 17.5 and 17.6. Section 17.7 discusses the three sources of funding for these expenditures**.**

17.2 Forecast of Capital Requirements

City Light is required to submit a six-year capital plan for each annual budget. Figure 17.1 shows each major component of the capital requirements forecast for years 2011-2016. City Light's capital improvement program (CIP) is projected to increase from $241.6 million in 2011 to $268.0 million in 2013 and then decrease to $195.5 million in 2016. CIP expenditures comprise on average 77% of total capital requirements during the six-year planning horizon.

Deferred conservation is projected to increase by over 50% between 2011 and 2012 and then grow on average by 3% annually after that. Deferred O&M is expected to be in the $13-$17 million range during 2011-2013, then increase to $31.6 million in 2014 and decline to the $21-$26 million range in 2015-2016. The big increase in 2014 is primarily due to the construction contract for the removal and site restoration of Mill Pond Dam associated with Boundary relicensing. Deferred High Ross charges are projected to remain fixed at $9.1 million. Components of the capital requirements forecast are discussed in the sections below.

Figure 17.1



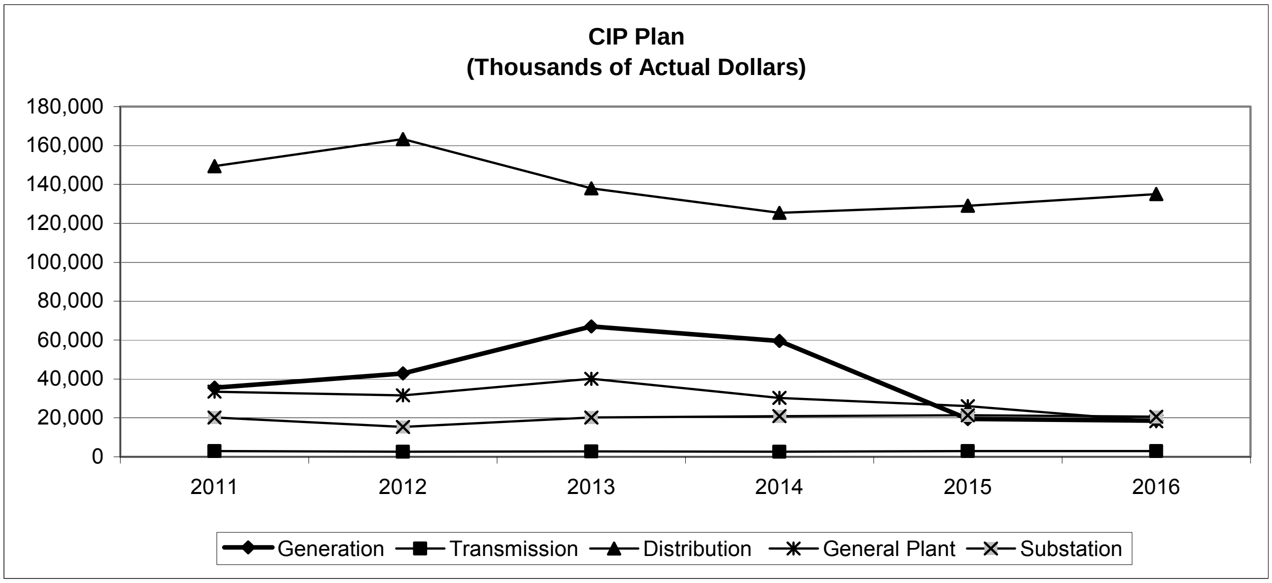
17.3 Major Projects in the Capital Improvement Expenditure Forecast

The financial 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 each project. Based on historical experience, the forecast assumes a 10% under-expenditure in CIP. Put another way, the amount input into the forecast is only 90% of the budgeted CIP expenditures.

As compared to the 2010-2015 CIP from the last budget, the current forecast reflects additional funding requirements for new projects or additions to previously approved projects. The largest project is Alaskan Way Viaduct and Seawall Replacement, which relocates SCL's infrastructure attached to the existing Viaduct ($23.2 million in 2011 and $44.7 million in 2012). The project also provides a replacement path for transmission through downtown Seattle. In addition, funds were added beginning in 2011 to replace the utility's aging infrastructure. Examples include the neighborhood cable injection/replacement program ($5.1 million in 2011 and $5.3 million in 2012) and meter reading software replacement ($0.5 million in both 2011 and 2012). Additional funds were also requested for Phase 2 of relocating overhead systems to underground in Burien ($4.7 million in 2011).

The forecast classifies CIP expenditures according to functional categories: generation, transmission, distribution, general plant and substation. Figure 17.2 shows these expenditures. Distribution is the largest category, which is projected to peak in 2012 at $163.3 million and then go down to $125.3 million in 2014 and increase after that to $135.1 million in 2016. The main driver behind the high distribution expenditure is the Alaskan Way Viaduct and Seawall Replacement project.

Figure 17.2



Generation expenditures are projected to peak in 2013 to 2014 when City Light plans to rebuild Boundary Units 55 and 56 generators and replace the turbine runners and when the major Boundary relicensing capital mitigation work begins. During the period 2011-2016 General Plant expenditures are trending downward as specific, larger information technology, communications, and facilities projects are coming to an end by 2016. Transmission and Substation costs are planned to remain relatively flat over the six-year plan.

Table 17.1 on the next page presents forecast information for selected CIP projects by major capital category for the years 2011-2016.[7] Each major expenditure category is discussed in more detail below for the six-year plan.

[7] CIP numbers have slightly changed since the rate increases for 2011-2012 presented in this RRA were calculated. However, these changes are very minor and have no impact on the size of the proposed rate increases. Table 17.1 presents the most recent CIP amounts which slightly differ from the CIP numbers reported elsewhere in this document.

Table 17.1
Selected CIP Projects
(Thousands of Actual Dollars)[8]

	2011	2012	2013	2014	2015	2016	6-Year Plan
Generation							
Skagit Plant Improvements	$ 13,816	8,745	34,686	33,213	3,157	439	94,056
Generators and Turbine Runners	9,456	21,423	22,316	12,971	6,907	6,364	79,437
Boundary Plant Improvements	7,835	8,846	6,776	8,118	3,637	3,576	38,788
Environmental Mitigation	1,769	1,563	1,996	4,191	3,455	3,226	16,200
Other Generation	2,628	2,308	1,188	1,016	2,238	4,908	14,287
Subtotal	$ 35,504	42,885	66,962	59,509	19,394	18,514	242,768
Transmission	$ 2,938	2,706	2,777	2,663	2,905	2,966	16,954
Distribution							
Service Connections	$ 28,085	28,349	30,401	30,174	30,888	31,640	179,538
Transportation Related	35,901	57,620	33,690	14,552	11,303	15,151	168,218
Capacity Additions	24,943	23,619	20,623	22,964	31,233	32,449	155,829
Pole Replacements	9,563	12,691	13,842	14,146	14,480	14,833	79,555
Reliability	12,321	10,492	6,746	11,717	11,996	11,643	64,914
Street and Floodlights	10,013	10,130	9,263	9,725	9,954	4,595	53,681
Underground Projects	8,492	9,197	7,710	7,733	7,856	5,518	46,506
Other Distribution	5,086	2,165	4,117	4,208	784	11,849	28,209
Smart Grid	509	2,338	6,668	4,138	6,165	3,488	23,306
26 kV Conversion	2,743	3,349	3,874	4,881	4,481	3,905	23,233
Suburban Undergrounding	11,824	2,335					14,160
Mobile Workforce		1,039	1,085	1,108			3,232
Subtotal	$ 149,480	163,324	138,019	125,346	129,141	135,071	840,380
General Plant							
Information Technology	$ 7,178	7,874	16,768	11,720	10,832	3,303	57,674
Vehicle Replacement	7,415	8,249	8,418	8,595	8,798	9,013	50,489
Other General Plant	4,022	2,381	6,382	6,478	2,940	2,689	24,892
Asset Management	10,808	9,285	3,686				23,779
Communications	3,103	2,933	3,007	1,604	1,640	1,327	13,614
Security	721	821	1,853	1,835	1,878	1,924	9,032
Rapid Storm Response (OMS)	211						211
Subtotal	$ 33,457	31,542	40,115	30,233	26,088	18,256	179,691
Substation	$ 20,182	15,410	20,163	20,857	21,353	20,687	118,652
Grand Total	**$ 241,562**	**255,867**	**268,036**	**238,607**	**198,880**	**195,493**	**1,398,446**

17.3.1 Generation Plant ($242.8 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 $242.8 million during the six-year planning period, averaging about $40.5 million per year and representing about 17% of planned expenditures for that period.

Skagit Plant Improvements ($94.1 million). The Skagit Hydroelectric Project generation plants include Ross, Gorge, Diablo and Newhalem powerhouses, dams and related facilities. The largest single project, Gorge Second Tunnel installation ($61.8 million), is discussed below. In addition, City Light will make investments ($32.3 million) at the Skagit powerhouses, facilities and grounds at Diablo, Ross, Gorge, Newhalem and related Skagit facilities to improve generating reliability and reduce electrical hazards. Investments include replacement of

[8] Most projects adjusted to reflect 90% under-expenditure assumed in forecast.

governors, transformers, breakers, switch gear and other equipment, installing additional security measures and other improvements.

Gorge Plant – Second Tunnel Installation ($61.8 million). The main purpose of the Gorge Auxilliary Tunnel project 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. This goal would be accomplished by boring a second tunnel parallel to the existing two-mile long tunnel. 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. The value of this additional generation is approximately $2.6 million per year.

Generator and Turbine Runner Rebuilds/Replacements ($79.4 million).

Replace Turbine Runners at Boundary Units 55 and 56 ($20.8 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 newly designed hydro turbines. 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 ($58.6 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 two units at the Skagit plant over the six-year period 2011-2016.

Boundary Plant Improvements ($38.8 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, among other things, to do work on switchyard transformers ($17.0 million), perform rock damage mitigation ($6.0 million) and improve radio communications ($2.8 million).

Environmental Mitigation ($16.2 million) This category includes three projects: Boundary Licensing Mitigation ($9.3 million), Skagit Licensing Mitigation ($1.0 million) and Endangered Species Act Mitigation ($5.9 million).

Boundary Dam is City Light's largest generating station, producing approximately 25 to 40% of its power supply. In order to continue to operate the facility, the City must obtain a new FERC license. In September 2009 City Light submitted the License Application to FERC and in March 2010 it submitted a comprehensive Settlement Agreement package along with a supplementary filing including addenda to the License Application and responses to FERC's November 18, 2009 Additional Information Requests. This project ($9.3 million) will conduct projects as required by the terms and conditions of a Settlement Agreement and new license to be issued by FERC in September 2011. Protection, mitigations and enhancement (PME) measures were negotiated with agencies with mandatory conditioning authority as part of a comprehensive Settlement Agreement and are binding on City Light per that Agreement even if they are not all contained in the new license. Continued operation of Boundary Hydroelectric Project is conditional upon obtaining a new license.

The Skagit Licensing Mitigation project ($1.0 million) enhances and protects wildlife habitat on utility-owned land in the Upper Skagit River and South Fork Nooksack River valleys to meet the obligations outlined in City Light's 1995 Skagit license. It includes land acquisition, restoration, and management.

Lastly, the Endangered Species Act Mitigation project ($5.9 million) protects and restores wildlife habitat in the Skagit and Tolt basins to implement the Endangered Species Program for recovery of listed species (chinook salmon, bull trout, and steelhead). Project costs include land purchase, restoration, assessment, and management.

Other Generation ($14.3 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 ($5.3 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 ($2.0 million). Improvements include power system stabilizers, generator and control system testing equipment, cyber security equipment, and system disturbance monitoring equipment.

17.3.2 Transmission Plant ($17.0 million)

Transmission plant includes poles, towers and conductors used to carry electricity from generation facilities to substations. Transmission expenditures are projected to total $17.0 million during the six-year planning period, averaging about $2.8 million per year and representing about 1% of planned expenditures for that period.

The transmission reliability project ($13.5 million) provides engineering, construction, and other work to improve or maintain the reliability of the overhead and 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. Current projects include rebuilding the 230 kV Creston-Duwamish wood H-frame transmission line and upgrading cathodic protection of underground transmission conductors.

The Transmission Inter-Agency project ($3.0 million) provides demand-driven improvements to City Light's transmission system, including reimbursable transmission work and relocations of transmission equipment to meet customer, other utility, agency, and regulatory requirements.

The purpose of this project is to accommodate other agencies' relocation schedules as feasible, given constraints of the transmission system, outage coordination with the Northwest Power Pool and the engineering and procurement of materials.

17.3.3 Distribution Plant ($840.4 million)

Distribution includes substations, lines, transformers and other distribution equipment as well as utility equipment relocation costs associated with transportation projects. The Department plans to spend about $840.4 million from 2011 to 2016 on improvements and additions to the distribution system, averaging $140.1 million per year and representing about 60% of total CIP expenditures.

Service Connections ($179.5 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.

Transportation Related ($168.2 million). The largest project in this group is Alaskan Way Viaduct and Seawall Replacement ($130.5 million), which is described in more detail below. Other large projects are Transportation Driven Relocations ($17.4 million) and Mercer Corridor Relocations ($11.0 million).

> **Alaskan Way Viaduct ($130.5 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. The Alaskan Way Viaduct Program will likely be the City's primary construction focus as its various projects impact traffic and roadway construction, seawall stabilization, urban design on the waterfront and expansion of the City's streetcar system. City Light has critical transmission and distribution infrastructure along the project corridor, all of which must be relocated once or twice during the project. The global nature of the Viaduct Program also provides the opportunity to make system improvements that will provide for increased reliability and capacity for our customers.
>
> The **Mercer Corridor West Phase Relocations** project relocates significant transmission and distribution facilities on the west end of the Mercer Street corridor as part of the Alaskan Way Tunnel project.
>
> **Transportation Driven Relocations ($17.4 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.

Mercer Corridor Relocations ($11.0 million). This project converts the existing overhead electrical distribution systems and a section of the existing overhead Broad-University transmission line to an underground configuration 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. This project provides for the construction of manageable and sustainable electrical power distribution infrastructure within this major transportation corridor improvement in the South Lake Union Urban Center. The costs of the project will be paid from both utility and non-utility funds. City Light will pay for 60% of civil and electrical power utility costs. Primary project costs, excavation and restoration costs, as well as the remaining 40% of civil and electrical power utility project costs, will come from non-utility funds.

Capacity Additions ($155.8 million). The expenditures projected in this group of projects are for building or re-conductoring line segments, 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 ($51.8 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.

Overhead and Underground Customer-Driven Capacity Additions ($32.4 million). These projects add capacity to the distribution system to accommodate increased load from new services. The purpose of these projects is to identify and upgrade the feeders that are impacted by specific, customer-initiated projects before the new load from those projects comes online. City Light is reimbursed by the customers for this work.

Underground System Capacity Additions ($24.8 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 2014 **($18.0 million)**. This project installs electrical service connections on the docks which support cruise ships moored in Elliott Bay. The project allows the ships to power their systems with clean energy while protecting the atmosphere. Without these electrical connections, the ships would use diesel power while in port.

Pole Replacements ($79.6 million). This project pays for a contractor to inspect and survey 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.

Reliability ($64.9 million) projects improve City Light's customer service and reliability by repairing and replacing failing equipment in order to avoid outages.

> **Network Rebuilds ($20.7 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.

> **Underground Equipment Replacements ($17.9 million).** This project replaces and improves undergound electrical system equipment that is failing or approaching the end of its useful life.

> **Overhead Equipment Replacements ($17.8 million).** This project replaces older equipment in City Light's distribution system that is nearing the end of its usable life, is overloaded, or is of an outdated design which requires replacement due to the lack of spare parts. These items include, but are not limited to, poles, crossarms, transformers, and open-wire secondaries. This work improves system reliability by reducing the chances of unplanned outages on the system.

Streetlights and Floodlights ($53.7 million). Lighting projects in the 2011 to 2016 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.

> **Streetlight LED Conversion Program ($28.3 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.

> **Transportation Street Lights ($7.9 million).** This project relocates Seattle City Light-owned streetlights as required by transportation projects.

Underground Projects ($46.5 million). This group of projects rebuilds or replaces underground systems in Seattle neighborhoods. Below are the largest two projects. Other large projects are an underground rebuild in Laurelhurst ($4.2 million) and the neighborhood voluntary undergrounding program ($2.2 million).

> **Neighborhood Cable Injection Program ($29.9 million).** This project uses cable injection in Seattle neighborhoods to extend the useful life of direct buried cables without replacing them and replaces those cables that are too deteriorated to benefit from injection.

> **Citywide Underground Initiative ($10.1 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 ($28.2 million). This group of projects provides funds for a variety of distribution activities, the largest of which is the **State Route 99 Capacity Additions and Relocations ($11.0 million)** project. This project relocates electrical infrastructure to assist in lowering the street level of State Route 99 and provides major capacity enhancements by increasing feeder and transmission capacity. Electrical work in South Lake Union is included.

Smart Grid ($23.3 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 more efficiently and the utility can manage its systems in a more cost-effective and efficient way. Smart Grid investments reflected in the CIP currently comprise two projects: Substation and Distribution Automation Systems.

> **Substation Automation System ($14.1 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.

> **Distribution Automation System ($9.2 million).** This project installs strategically placed power line switches which are able to perform automatic outage restoration, shift blocks of load to maximize efficiencies 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.

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. This conversion increases capacity to deliver power to City Light customers, rebuilds and maintains the backbone of City Light’s system, saves energy by reducing transformer and line losses, improves quality and reliability of service to customers, and releases unit substation properties for better neighborhood uses.

Surburban Undergrounding ($14.2 million). City Light has franchise agreements with the cities of Burien, Lake Forest Park, SeaTac, Shoreline and Tukwila that allow them to request that overhead lines be placed underground. In the current plan only three franchise cities--Burien, SeaTac and Shoreline--have requested such undergrounding. The cost of these projects is recovered over time, through City Light rates charged in those jurisdictions during the 25 years following project completion.

Mobile Workforce ($3.2 million). Starting in 2012, this project provides mobile communication and computing equipment for City Light workers to use in the field. This project supports City Light's efforts to implement work and asset management, smart grid and performance management.

17.3.4 General Plant ($179.7 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 $179.7 million will provide for general plant improvements and/or replacement over the 2011-2016 period, averaging about $30.0 million per year and representing about 13% of total capital expenditures over the six-year period. Major components are discussed below.

Information Technology ($57.7 million) The major information technology project ($18.1 million) included in the 2011-2016 CIP funds replacement and improvement of the Utility's information technology infrastructure. This infrastructure provides applications, data storage and print services to the utility. It also supports activities and applications including Microsoft Outlook, remote connectivity, E-tagging for power marketing, the City InWeb and network, common (with the City) and City Light applications, UNIX services and infrastructure change management. Components purchased by this project include servers, network and communications equipment, disk storage and application/operating system software. Infrastructure is upgraded or replaced based upon a combination of factors, such as maintenance schedules, equipment warranties, availability of vendor support, consultant recommendations, application growth and security demands. This project helps to maintain a stable, reliable computing environment at the utility. Other projects include the energy management system ($17.4 million), customer information system ($12.0 million) and PC, Windows, and Software Upgrades ($6.0 million).

Vehicle Replacement ($50.5 million). This project replaces and expands City Light's heavy-duty mobile equipment fleet. This project also funds the gradual replacement of light-duty vehicles owned by City Light, including those previously leased from the Fleets & Facilities Department and now owned by City Light.

Other General Plant ($24.9 million). This project includes expenditures for non-electrical facilities at North and South Service Centers ($4.5 million), including the South Service Center Spokane Exit Modification ($1.3 million), which is required to realign main yard and service vehicle gate to access the new 4th Avenue South intersection. It also makes provision for workplace and process improvement ($5.9 million), special work equipment ($4.8 million) and other environmental and safety modifications.

Asset Management ($23.8 million). Asset management funds will be used to design, develop, and implement hardware, software, and related tools to track asset information and work history, which will enable the Utility to make better asset investment decisions. The project will implement Oracle WAMS (Work and Asset Management Systems) and establish standard business processes.

Communications ($13.6 million). The major communications projects included in the 2011-2016 CIP will improve fiber optic cable and radio communications infrastructure that supports distribution, transmission and generation control systems.

Security ($9.0 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.

Rapid Storm Response (OMS) ($0.2 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. It will be completed in 2011, though most of it will be operational by the end of 2010.

17.3.5 Substation Plant ($118.7 million)

These projects include building upgrades, equipment improvements and replacements, and capacity additions at City Light's substations to make substations more reliable and safer and meet increasing load demands. A specific project example is North Downtown Substation Development ($6.8 million), which designs and builds a 200 MVA substation in the North Downtown area to meet load growth and support development of an underground network. Substation Plant projects comprise 8% of CIP and are projected to average $19.8 million per year during 2011-2016.

17.4 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-saving measures.

The Department's 2008 Integrated Resource Plan ("IRP") called for significantly increasing the Department's future conservation targets. In 2008, the Department released a Five-Year Conservation Action Plan outlining increased savings goals, budgets and staffing. The 2009 savings goal was 10.3 aMW, with annual savings targets ramping up to 14 aMW by 2012. The Department measures energy conservation results in terms of amount and duration of savings using regionally and nationally recognized methods. In 2009, the Department achieved 13.24 aMW (115,982 MWh) of energy savings. Total savings since the program's inception amount to approximately 130 aMW (1,138,800 MWh), representing more than 10% of the Department's total energy needs in 2009. Also, the passage of Initiative 937 has influenced the Department's conservation targets. For 2010 and 2011, the total energy savings target is 19.68 aMW. The Department expects to meet or exceed this near-term target.

The current deferred conservation expenditures are projected to increase from $26.1 million in 2011 to $44.2 million in 2016.

17.5 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 required under the terms of Federal licenses of the Skagit, South Fork Tolt and Boundary projects and in accordance with a 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 $13.9 million in 2011, $16.5 million in 2012 and $15.2 million in 2013. They are then forecasted to increase by over 50% to $31.6 million in 2014 and decline to the $21-$26 million range in 2015-2016. The big increase in 2014 is primarily due to the construction contract for the removal and site restoration of Mill Pond Dam associated with Boundary relicensing. Another big increase is in the cost of the Upstream Passage study program, which will involve hiring of a consultant in 2014 who will be designing and locating a prototype fish trap and haul facility.

17.6 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.

17.7 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 15); 2) revenue from retail customer rates and other operating revenues (discussed in detail in Chapters 1 and 3); and 3) proceeds from debt (discussed in detail in Chapter 16). See Chapter 18 for the amounts for each of these funding sources projected in the six-year plan.

Per Resolution 31187, the Department is required to fund its CIP so that on average, over the term of any given six-year CIP, it will fund 40% of that CIP with cash from operations. The following table shows cash from operations available to fund CIP. The current six-year forecast shows that City Light will achieve the target of 40% (the average in Table 17.2 is 45%).[9]

Table 17.2
Percentage of Cash from Operations to Fund CIP
($ millions)

	2011	2012	2013	2014	2015	2016
CIP	$ 241.6	$ 255.9	$ 268.0	$ 238.6	$ 198.9	$ 195.5
Cash from Operations	$ 72.0	$ 94.1	$ 103.7	$ 113.3	$ 119.1	$ 115.6
% of CIP from Operations	30%	37%	39%	48%	60%	59%

[9] As was mentioned in footnote 8 CIP numbers slightly differ from Cash Flow table elsewhere in this document but will be the same in the Adopted RRA. See footnote 8 in this chapter for more detail.

Chapter 18 - Six Year Rate Outlook

18.1 Overview

This chapter contains a high-level discussion of the six year rate outlook. A major revision to City Light's Strategic Plan is currently under way and the results will likely change the rate outlook substantially. However, since it is not available as of the writing of this document, the long term rates contained in this *RRA* are the result of simply extending the current proposed budget and Capital Plan, with accepted BIPs, out for six years.

18.2 Discussion of Six Year Rate Forecast

Table 18.1 summarizes the cash flow, and the resulting rates. A full complement of reports can be found in Appendix 1.

Rates are expected to increase at an average rate of about 4% annually through 2016. The anomalous rate decrease in 2014 (and 8.6% increase that follows in 2015) is due to a major land sale assumed for that year, which increases Other Revenue by about $30 million over the other future years.

According to City Light's financial policy guidelines, Retail Power Sales must be increased (via increasing rates) so that the Amount Available for Debt Service equals 1.8 times Debt Service. Only a portion of the upward pressure on rates in 2011-2016 can be attributed to O&M costs rising more quickly than non-retail revenues (i.e., inflation). As shown in Table 18.1, Cash to Expenses less Cash from Revenues excluding Retail Power Sales are rising at the average rate of $22 million per year, contributing about half of the 4% average annual increase. Another source of rate pressure is increasing levels of debt stemming from capital spending.

Capital spending and debt is shown in Table 18.2. Total capital spending, which includes the CIP, deferred conservation and other deferred O&M, increases substantially through 2013, then begins to decline slightly in 2014-2016. See Chapter 17 for more information on CIP drivers. As a result, the Department expects to issue about $175 million in new debt annually on average, and the total debt outstanding is projected to reach close to $2 billion by year-end 2016. Debt service increases commensurately, increasing debt service coverage needs by about $25 million each year. This translates into annual rate increases that are about 2% higher than they would otherwise be. Notable in Table 18.2, debt to capitalization continues to steadily decrease, providing an indication that the overall debt burden assumed by City Light is reasonable.

Table 18.1
Rate and Cash Flow Summary 2011-2016

($ million)

	2011	2012	2013	2014	2015	2016
Rate Change from Prior Year (1)	**4.3%**	**4.2%**	**4.7%**	**-1.1%**	**8.6%**	**2.9%**
Cash from Revenues						
Retail Power Sales	$651.5	$699.2	$736.0	$733.3	$802.1	$833.8
Revenue from RSA Surcharge	11.7	0.0	0.0	0.0	0.0	0.0
Wholesale Power, Net (2)	110.5	102.1	103.7	106.7	103.5	107.6
Other Revenue	70.8	70.2	75.6	106.0	77.4	74.6
Total	**$844.6**	**$871.5**	**$915.3**	**$946.0**	**$983.0**	**$1,015.9**
Cash to Expenses						
Power Contracts	$282.8	$289.3	$291.5	$305.1	$315.7	$330.5
Other O&M	272.5	267.7	278.4	279.1	288.4	297.6
Cash to RSA	(32.5)	(2.9)	(4.1)	(5.0)	(5.8)	(6.1)
Total	**$522.8**	**$554.0**	**$565.8**	**$579.2**	**$598.4**	**$622.0**
Cash to Expenses less Cash from Revenues excluding Retail Power Sales	329.8	381.7	386.4	366.5	417.4	439.8
% Increase	-4%	16%	1%	-5%	14%	5%
Amount Available for Debt Service	**$256.8**	**$311.6**	**$341.3**	**$356.8**	**$373.0**	**$381.7**
Debt Service	142.7	173.1	189.6	198.2	207.2	212.0
Taxes and Other Expenses	42.1	44.4	48.0	45.3	46.6	54.1
Cash from Operations	**$72.0**	**$94.1**	**$103.7**	**$113.3**	**$119.1**	**$115.6**

(1) Rate changes are the forecasted difference between rates on December 31 and January 1 the next year. BPA pass-through changes are not reflected in the % increase, but are included in the base year for the % increase calculation. RSA surcharges are excluded from all calculations.

(2) 2011-12 are the rate assumption based on historical actuals. All other years are current forecasts as of 8-20-10, and assume normal water.

Table 18.2
Capital Spending and Debt Summary 2011-2016

($ million)

	2011	2012	2013	2014	2015	2016
Capital Projects	$240.2	$260.7	$261.5	$237.3	$191.2	$188.1
Deferred O&M	48.7	65.1	65.3	82.7	74.3	78.8
Total Capital Spending	**$288.9**	**$325.9**	**$326.8**	**$320.0**	**$265.5**	**$266.8**
Debt Issued	$210.0	$200.0	$177.5	$200.6	$128.8	$133.8
Year End Total Debt Outstanding	$1,606.7	$1,723.5	$1,810.0	$1,914.0	$1,940.5	$1,971.2
Debt Service	$142.4	$172.5	$188.9	$197.5	$206.4	$211.3
Debt Service Coverage Needs (1.8x)	**$256.3**	**$310.5**	**$340.0**	**$355.5**	**$371.6**	**$380.4**
Debt as a % of Total Capitalization	63%	63%	61%	61%	59%	57%

Appendix 1 – Financial Planning Model Forecast: 2009 - 2016

2011-2012 Revenue Requirements Analysis

RateStudy2010_08_20_Case_04
Finished September 23, 2010, 13-42-47

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NOTE: Data for 2009 are included. Most of those numbers are accurate and useful for historical comparison but not all the details have been adjusted at this time to reflect audited results.

Crosswalk Explaining the Relationship Between Various Retail Revenue Amounts

	2011	2012
Revenue from All Retail Customers (Table 2.01)	**$3,059,715**	**$3,339,528**
-Revenue from Distribution Capacity Charge	204,309	208,899
-Revenue from Green Power Residential	317,487	370,401
-Revenue from Green Power Non-Residential	12,513	14,599
-Revenue from Power Factor Charges	2,525,406	2,745,629
Revenue from MWh, KW and BSC (Table 2.01)	**$644,934,797**	**$692,169,441**
+Rate Discounts	6,581,448	7,064,615
=Retail Power Sales before Discounts (Cash Flow Table)	**$651,516,246**	**$699,234,056**
Revenue from MWh, KW and BSC (Table 2.01)	**$644,934,797**	**$692,169,441**
+Misc Retail Revenue (see below)	4,907,759	5,734,292
+RSA Revenue	11,716,340	
=Retail Power Sales Inside System (Table 1.01 & 1.02)	**$661,558,897**	**$697,903,733**

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Cash Flow 2008- 2017 ($M)								
Cash from Revenues								
Retail Power Sales before Discounts	545.15	616.67	651.52	699.23	736.02	733.28	802.08	833.75
Revenue from RSA Surcharge		17.43	11.72					
Wholesale Power, Net	68.37	50.90	110.50	102.10	103.70	106.69	103.54	107.58
Power Contracts	23.92	19.92	21.21	20.60	22.37	22.60	21.36	17.17
Power Marketing, Net	15.16	12.27	15.21	8.20	8.71	9.34	8.14	8.38
Other Outside Sources	29.68	29.23	29.99	30.99	30.58	57.98	32.16	32.95
Interest on Cash Accounts	4.14	3.22	4.43	10.37	13.95	16.09	15.72	16.10
Cash from (to) Rate Stabilization Account		(43.92)	(32.48)	(2.94)	(4.13)	(4.98)	(5.84)	(6.14)
Total	686.42	705.70	812.08	868.56	911.21	941.01	977.15	1,009.79
Cash to Expenses								
Power Contracts	257.36	275.35	282.83	289.29	291.47	305.13	315.74	330.51
Production	27.21	27.66	36.22	35.79	36.58	37.70	38.90	41.14
Transmission	8.87	7.96	9.47	9.67	9.89	10.11	10.34	10.58
Distribution	57.01	55.72	68.20	68.97	66.60	68.08	69.69	71.36
Conservation	4.77	4.13	11.03	11.57	8.25	8.46	8.65	8.84
Customer Accounting	30.39	29.92	30.00	30.60	31.24	31.94	32.69	33.47
Administration	61.89	54.17	71.70	63.07	75.69	72.52	73.86	75.31
Rate Discounts	5.36	6.11	6.58	7.06	7.47	7.50	8.26	8.67
Uncollectible Revenue	5.27	5.47	5.95	6.28	6.61	6.59	7.20	7.48
State Taxes and Franchise Payments	28.56	32.36	33.31	34.63	36.09	36.16	38.86	40.74
Total	486.68	498.86	555.29	556.95	569.89	584.18	604.19	628.10
Amount Available for Debt Service	**199.74**	**206.85**	**256.80**	**311.61**	**341.33**	**356.83**	**372.96**	**381.69**
Cash to Other Expenses								
City Taxes	33.71	38.97	41.43	43.25	45.55	45.37	49.40	52.11
Bond Reserve Account								
Balance Sheet Accounts	(1.09)	13.14	0.71	1.17	2.44	(0.09)	(2.78)	1.96
Debt Service	144.86	118.41	142.66	173.11	189.61	198.21	207.20	212.02
Total	177.49	170.52	184.81	217.54	237.60	243.49	253.82	266.09
Cash Available for Capital Projects								
from Operations	**22.25**	**36.33**	**71.99**	**94.07**	**103.73**	**113.34**	**119.14**	**115.60**
from Contributions	28.85	28.67	31.61	19.45	22.12	21.36	22.31	37.62
from Bond Proceeds	194.58	160.02	188.41	212.73	202.74	188.75	129.27	119.37
Total	245.69	225.02	292.01	326.25	328.58	323.45	270.72	272.58
Cash to Capital Projects, etc.								
Capital Projects	197.45	173.80	242.87	261.14	263.03	240.50	196.45	193.81
Conservation Projects	29.71	30.08	26.13	39.50	41.23	42.27	43.23	44.18
Deferred Project License Charges	9.43	12.04	13.90	16.51	15.22	31.57	21.94	25.49
Deferred High Ross Charges	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
Total	245.69	225.02	292.01	326.25	328.58	323.45	270.72	272.58

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Key Financial Indicators								
Retail Market Information								
Average Retail Rate before Discounts ($/MWh)	$56.61	$66.67	$69.17	$72.95	$76.40	$75.55	$82.03	$84.42
Rate Increase	0.35%	16.10%	4.31%	4.16%	4.73%	(1.11%)	8.57%	2.91%
Retail Sales (MWH)	9,629,540	9,249,606	9,419,707	9,584,676	9,633,360	9,705,588	9,777,982	9,876,639
Average Residential Monthly Bill before Discounts	$44.42	$52.45	$55.44	$56.94	$59.67	$59.02	$63.97	$65.82
Wholesale Market Information								
Net Wholesale Sales (MWh)	1,830,609	1,716,897	2,654,116	2,216,703	2,001,999	2,022,432	1,930,774	1,962,141
Net Wholesale Revenue per MWh	$37.35	$29.65	$41.63	$46.06	$51.80	$52.75	$53.63	$54.83
Price of Natural Gas ($/MMBTU)	$3.74	$4.18	$4.55	$6.33	$7.54	$7.70	$7.88	$8.08
Net Income (Million $)	**$34.2**	**$28.1**	**$85.5**	**$90.7**	**$113.5**	**$136.2**	**$123.1**	**$146.3**
Debt Issued (Million $)		$791.77	$210.00	$200.00	$177.50	$200.60	$128.75	$133.80
Year-end Cash Balance Position (Million $)								
Operating Cash Account	$32.7	$56.8	$118.4	$97.0	$65.9	$69.8	$63.3	$72.3
Construction Account	$0.0	$51.3						
RSA		$68.9	$101.4	$104.3	$108.5	$113.4	$119.3	$125.4
Other Restricted Funds	$31.6	$3.0	$13.0	$20.4	$25.2	$31.9	$37.0	$41.7
Year-end Balance of Total Cash	**$64.3**	**$180.0**	**$232.7**	**$221.7**	**$199.5**	**$215.1**	**$219.6**	**$239.4**
Year-End Balance of Accumulated Net Income (Million $)	$824.3	$851.6	$934.5	$1,022.9	$1,135.3	$1,205.4	$1,327.3	$1,472.5
Year-end Balance of Debt Outstanding (Million $)	$1,357.7	$1,466.8	$1,606.7	$1,723.5	$1,810.0	$1,914.0	$1,940.5	$1,971.2
Debt as a % of Total Capitalization	**62.2%**	**63.3%**	**63.2%**	**62.8%**	**61.5%**	**61.4%**	**59.4%**	**57.2%**
% of Capital Req from Operations	9%	16%	25%	29%	32%	35%	44%	42%
% of Capital Req from Contributions	12%	13%	11%	6%	7%	7%	8%	14%
% of Capital Req from Bond Proceeds	79%	71%	65%	65%	62%	58%	48%	44%
Revenue Available for Debt Service (Million $)	$201.8	$201.1	$256.8	$311.6	$341.3	$356.8	$372.9	$381.7
1st & 2nd Lien Debt Service (Million $)	$144.9	$118.4	$142.7	$173.1	$189.6	$198.2	$207.2	$212.0
Debt Service Coverage - Current Year	**1.39**	**1.70**	**1.80**	**1.80**	**1.80**	**1.80**	**1.80**	**1.80**
Probability Will Have Cash from Operations			95.92	99.15	98.55	99.04	99.08	98.86
Debt Service Coverage Target	2.00	1.80	1.80	1.80	1.80	1.80	1.80	1.80
Debt Service * Target DSC (Million $)	$289.7	$213.1	$256.8	$311.6	$341.3	$356.8	$373.0	$381.6
Rate of Inflation (percent)	0.44%	1.75%	1.80%	1.88%	2.06%	2.20%	2.36%	2.44%

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
1.01 - STATEMENT OF OPERATIONS								
Operating Revenue								
Retail Power Sales Inside System	545,110,850	625,925,230	661,558,897	697,903,733	734,409,595	731,772,078	799,956,461	831,368,659
Short-Term Wholesale Power Sales	88,650,460	80,850,661	137,913,453	146,005,050	155,186,585	159,589,026	158,208,191	164,874,882
Other Power Sales	65,008,900	65,722,320	78,042,170	54,242,734	61,265,620	62,875,652	62,786,984	64,245,754
Transmission Services	1,773,144	3,100,666	2,161,946	2,203,699	2,249,017	2,298,457	2,352,655	2,410,042
Other Revenue	22,584,687	21,128,215	21,813,381	22,242,537	22,772,665	23,330,112	23,879,590	24,439,555
Transfers From (To) the RSA								
Total	**723,128,042**	**752,808,964**	**869,013,209**	**919,656,160**	**971,755,666**	**974,889,518**	**1,041,347,917**	**1,081,202,693**
Operating Expense								
Operations and Maintenance Expense								
Generation	28,621,886	29,763,313	39,230,868	40,454,589	42,245,726	44,400,157	47,322,530	50,188,404
Long-Term Purchased Power	202,003,061	225,376,807	233,038,641	242,445,622	245,021,827	256,891,050	267,042,035	284,203,301
Short-Term Wholesale Power Purchases	24,570,643	34,239,862	32,503,215	49,090,694	56,779,682	58,304,537	60,204,132	62,963,828
Power-Related Wholesale Purchases	27,674,222	25,898,098	26,687,379	19,121,063	21,846,982	22,334,639	22,864,157	23,419,048
Other Power Costs	8,438,655	10,045,966	10,608,358	11,774,184	12,376,297	13,034,909	13,753,066	15,374,019
Transmission	8,964,963	8,063,563	9,567,204	9,771,007	9,986,574	10,208,891	10,438,547	10,674,819
Wheeling	38,109,121	39,551,849	39,873,009	39,210,070	40,112,878	41,093,581	42,163,611	43,295,387
Distribution	57,005,441	55,720,660	68,199,039	68,973,687	66,596,860	68,080,486	69,688,151	71,358,351
Conservation	16,920,830	17,487,568	25,481,175	27,658,630	26,173,198	28,195,179	30,138,179	32,020,366
Customer Accounting	35,661,790	35,393,318	35,953,357	36,881,649	37,849,104	38,521,633	39,888,945	40,954,149
Administration	73,217,198	56,106,377	68,325,253	63,850,537	71,337,242	72,779,858	74,524,605	76,268,713
Subtotal	**521,187,812**	**537,647,382**	**589,467,498**	**609,231,731**	**630,326,371**	**653,844,921**	**678,027,958**	**710,720,384**
Taxes and Depreciation								
Taxes	62,274,652	71,325,183	74,742,074	77,878,473	81,642,101	81,536,931	88,258,571	92,852,494
Depreciation	80,693,284	83,358,157	85,456,491	93,093,516	99,844,675	103,673,497	104,327,731	98,876,309
Total	**664,155,748**	**692,330,722**	**749,666,063**	**780,203,720**	**811,813,147**	**839,055,349**	**870,614,260**	**902,449,188**
Net Operating Revenue	**58,972,293**	**60,478,243**	**119,347,146**	**139,452,440**	**159,942,519**	**135,834,169**	**170,733,656**	**178,753,506**
Nonoperating Revenue (Expense)								
Investment Income	2,612,978	3,250,621	4,427,862	10,372,915	13,954,058	16,091,466	15,719,543	16,102,713
Gain (Loss) On Sale Of Property	28,921	718,790	2,546,256	2,250,000	1,100,983	46,928,759	1,154,204	1,179,709
Other Income(Expense) Net		104,426						
Interest Expense								
Amort of Debt Expense								
Total								
Fees, Grants and Transfers								
Suburban Undergrounding	1,320,637	5,893,000	11,597,000	2,595,000	2,117,000	2,163,000		
Capital - Cash total	22,533,173	22,890,403	26,875,093	19,452,023	22,118,640	21,364,978	22,306,010	37,616,236
Capital - Non-Cash	19,559,652	10,133,195	10,315,000	10,509,000	10,726,000	10,961,000	11,220,000	11,493,000
Operating	1,695,506	1,813,009	300,000	115,000				
Total	**45,108,969**	**40,729,607**	**49,087,093**	**32,671,023**	**34,961,640**	**34,488,978**	**33,526,010**	**49,109,236**
Net Income	**34,157,998**	**28,058,608**	**85,463,059**	**90,673,893**	**113,525,457**	**136,152,130**	**123,149,622**	**146,310,614**

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
1.02 - SUMMARY OF HISTORICAL AND PROJECTED OPERATING RESULTS								
Operating Revenue								
Retail Power Sales Inside System	545,110,850	625,925,230	661,558,897	697,903,733	734,409,595	731,772,078	799,956,461	831,368,659
Short-Term Wholesale Power Sales	88,650,460	80,850,661	137,913,453	146,005,050	155,186,585	159,589,026	158,208,191	164,874,882
Other Power Sales	65,008,900	65,722,320	78,042,170	54,242,734	61,265,620	62,875,652	62,786,984	64,245,754
Transmission Services	1,773,144	3,100,666	2,161,946	2,203,699	2,249,017	2,298,457	2,352,655	2,410,042
Transfers From (To) the RSA		(43,918,128)	(32,476,637)	(2,941,593)	(4,127,816)	(4,975,806)	(5,835,965)	(6,136,199)
Other Revenue	22,584,687	21,128,215	21,813,381	22,242,537	22,772,665	23,330,112	23,879,590	24,439,555
Total	**723,128,042**	**752,808,964**	**869,013,209**	**919,656,160**	**971,755,666**	**974,889,518**	**1,041,347,917**	**1,081,202,693**
Operating Expense								
Generation	28,621,886	29,763,313	39,230,868	40,454,589	42,245,726	44,400,157	47,322,530	50,188,404
Long-Term Purchased Power	202,003,061	225,376,807	233,038,641	242,445,622	245,021,827	256,891,050	267,042,035	284,203,301
Short-Term Wholesale Power Purchases	24,570,643	34,239,862	32,503,215	49,090,694	56,779,682	58,304,537	60,204,132	62,963,828
Power-Related Wholesale Purchases	29,163,780	27,593,371	26,687,379	19,121,063	21,846,982	22,334,639	22,864,157	23,419,048
Contra Expense Accounts	(1,489,558)	(1,695,273)						
Other Power Costs	8,438,655	10,045,966	10,608,358	11,774,184	12,376,297	13,034,909	13,753,066	15,374,019
Transmission	8,964,963	8,063,563	9,567,204	9,771,007	9,986,574	10,208,891	10,438,547	10,674,819
Wheeling	38,109,121	39,551,849	39,873,009	39,210,070	40,112,878	41,093,581	42,163,611	43,295,387
Distribution	57,005,441	55,720,660	68,199,039	68,973,687	66,596,860	68,080,486	69,688,151	71,358,351
Conservation	16,920,830	17,487,568	25,481,175	27,658,630	26,173,198	28,195,179	30,138,179	32,020,366
Customer Accounting	35,661,790	35,393,318	35,953,357	36,881,649	37,849,104	38,521,633	39,888,945	40,954,149
Administration	73,217,198	56,106,377	68,325,253	63,850,537	71,337,242	72,779,858	74,524,605	76,268,713
Subtotal	**521,187,812**	**537,647,382**	**589,467,498**	**609,231,731**	**630,326,371**	**653,844,921**	**678,027,958**	**710,720,384**
Taxes Excluding City Taxes	28,565,000	32,356,550	33,309,861	34,627,371	36,087,332	36,161,938	38,857,967	40,741,312
Total	**549,752,812**	**570,003,932**	**622,777,360**	**643,859,102**	**666,413,702**	**690,006,859**	**716,885,925**	**751,461,696**
Net Operating Revenue (Acctng)	**173,375,230**	**182,805,033**	**246,235,850**	**275,797,058**	**305,341,964**	**284,882,659**	**324,461,992**	**329,740,998**
Amortization	10,102,948	10,881,440	7,760,020	22,638,238	25,146,944	27,616,232	30,661,747	33,342,992
Investment Income	4,142,550	3,216,112	4,427,862	10,372,915	13,954,058	16,091,466	15,719,543	16,102,713
Other Income (Exp)	(1,012,961)	104,426	(272,805)	(279,258)	(285,863)	(292,625)	(299,546)	(306,631)
Proceeds from Sale of Property	1,000,000	1,725,097	2,546,256	2,250,000	1,100,983	27,728,759	1,154,204	1,179,709
Proceeds from Suburban Undergrounding	417,227	601,652	691,417	924,094	1,133,396	1,221,143	1,283,619	1,349,291
Operating Fees and Grants	1,695,506	1,813,009	300,000	115,000				
Claims net of Current Year Accruals	9,218,102	(224,598)	(5,587,831)	(1,488,877)	(6,677,240)	(2,117,270)	(1,768,314)	(1,533,539)
Non-Cash Power Expenses net of Revenues	2,861,440	155,742	668,787	1,252,654	1,584,598	1,670,275	1,721,383	1,783,550
Revenue Available for Debt Service	**201,800,042**	**201,077,914**	**256,769,556**	**311,581,824**	**341,298,840**	**356,800,639**	**372,934,628**	**381,659,083**
Debt Service								
1st Lien Bonds Debt Srvc	144,805,234	118,371,944	142,658,754	173,113,109	189,609,202	198,209,490	207,197,917	212,019,566
2nd Lien Bonds Debt Srvc	59,003							
Bank Notes		33,121						
Total	**144,864,238**	**118,405,065**	**142,658,754**	**173,113,109**	**189,609,202**	**198,209,490**	**207,197,917**	**212,019,566**
Debt Service Coverage Ratios								
1st-Lien Bonds	1.39	1.70	1.80	1.80	1.80	1.80	1.80	1.80
1st & 2nd-Lien Bonds	1.39	1.70	1.80	1.80	1.80	1.80	1.80	1.80
Debt Service as a Pct of Ret Rev	26.6%	18.9%	21.6%	24.8%	25.8%	27.1%	25.9%	25.5%
Average Retail Revenue per MWh	$56.61	$67.67	$70.23	$72.81	$76.24	$75.40	$81.81	$84.18

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
1.03 Funds Required / Provided								
Funds Required:								
Capital Expenditures								
Capital Improvement Projects								
Generation	27,416,782	24,830,220	35,504,273	42,885,272	66,962,083	59,508,750	19,393,922	18,133,435
Transmission	1,022,259	2,876,484	2,937,920	2,706,285	2,776,935	2,662,742	2,904,901	2,965,551
Substation	45,984,058	7,037,474						
Distribution	92,308,869	109,516,840	171,203,233	184,821,544	162,647,048	154,043,763	152,990,945	156,499,024
General Plant	30,713,943	29,543,852	33,221,255	30,728,121	30,642,177	24,284,665	21,156,162	16,207,812
Total	**197,445,911**	**173,804,870**	**242,866,682**	**261,141,222**	**263,028,244**	**240,499,920**	**196,445,929**	**193,805,821**
Conservation	29,707,906	30,080,469	26,134,744	39,496,779	41,234,532	42,274,787	43,227,753	44,182,993
Deferred O&M Costs	8,903,925	11,453,350	12,755,778	16,253,251	15,007,710	31,361,260	21,943,041	25,488,296
Deferred High Ross Charges	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333	9,103,333
City Tax on Suburban Undergrounding	320,808	353,580	695,820	155,700	127,020	129,780		
State Tax on Suburban Undergrounding	207,082	228,236	449,152	100,504	81,991	83,773		
Total Funds Required	**245,688,965**	**225,023,838**	**292,005,508**	**326,250,789**	**328,582,831**	**323,452,853**	**270,720,056**	**272,580,444**
Funds Provided:								
Proceeds from Operations								
Revenue Available for Debt Service	201,800,042	201,077,914	256,769,556	311,581,824	341,298,840	356,800,639	372,934,628	381,659,083
Less Debt Service	144,864,238	118,405,065	142,658,754	173,113,109	189,609,202	198,209,490	207,197,917	212,019,566
Less City Taxes	33,709,652	38,968,633	41,432,213	43,251,102	45,554,770	45,374,993	49,400,604	52,111,183
Change in Materials and Supplies	2,821,875							
Change in Unbilled Revenue	(118,995)	(6,342,722)	(1,256,027)	(1,620,759)	(1,910,648)	412,996	(1,856,991)	(1,491,473)
Change in A/R (Retail Revenue)	(1,614,314)	(6,798,636)	541,058	447,126	(526,527)	(319,904)	4,633,569	(469,667)
Add Other Funds Required (Net)	1,088,566	(13,141,358)	(714,969)	(1,173,633)	(2,437,175)	93,092	2,776,578	(1,961,140)
Total	**24,314,718**	**30,562,857**	**71,963,621**	**94,043,980**	**103,697,694**	**113,309,248**	**119,112,685**	**115,567,194**
Proceeds from Contributions								
Capital Fees and Grants		1,338,401	2,215,000	482,000	814,000	1,062,000	1,932,000	2,889,000
Contributions in Aid - Cash	28,633,994	25,029,757	24,660,093	18,970,023	21,304,640	20,302,978	20,374,010	34,727,236
BPA Payments for Conservation Deferred	217,857	2,300,000	4,732,690					
Total	**28,851,851**	**28,668,159**	**31,607,783**	**19,452,023**	**22,118,640**	**21,364,978**	**22,306,010**	**37,616,236**
Proceeds from(to) Working Capital Account	**30,426,478**	**(24,061,847)**	**(61,637,469)**	**21,376,189**	**31,127,069**	**(3,892,037)**	**6,478,889**	**(8,955,782)**
Proceeds from Sale of Bonds		254,510,944	208,740,000	198,800,000	176,435,000	199,396,400	127,977,500	132,997,200
Proceeds from 1st-Lien Bonds - Input		254,510,944	210,000,000	200,000,000				
Proceeds from 1st-Lien Bonds - AF					177,500,000	200,600,000	128,750,000	133,800,000
Less Debt Issue Costs - Input		(3,766,877)	(1,260,000)	(1,200,000)				
Less Debt Issue Costs - AF					(1,065,000)	(1,203,600)	(772,500)	(802,800)
Less Discount (or Plus Premium) on Debt Issued		62,067,032						
Less Charge on Refunded Debt		(58,300,156)						
Less Deposits to Bond Reserve			(10,000,000)					
Total		254,510,944	198,740,000	198,800,000	176,435,000	199,396,400	127,977,500	132,997,200
Total Funds Provided	**83,593,048**	**289,680,113**	**240,673,934**	**333,672,192**	**333,378,402**	**330,178,589**	**275,875,084**	**277,224,848**
Pct of Total Funds Required Financed with Funds Available From Current Operations	10%	14%	25%	29%	32%	35%	44%	42%
Probability Will Have Cash From Operations			96	99	99	99	99	99
A&G Expenditures Recognized as Capital Expenditures	29,675,942	29,498,097	27,578,958	28,130,537	28,717,145	29,357,082	30,050,346	30,770,275

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
1.04 - Net Earnings								
Revenue Available for Debt Service	**201,800,042**	**201,077,914**	**256,769,556**	**311,581,824**	**341,298,840**	**356,800,639**	**372,934,628**	**381,659,083**
Minus Cash Adjustments								
Investment Income	4,142,550	3,216,112	4,427,862	10,372,915	13,954,058	16,091,466	15,719,543	16,102,713
Other Income	(1,012,961)	104,426	(272,805)	(279,258)	(285,863)	(292,625)	(299,546)	(306,631)
Proceeds from the Sale of Properties	1,000,000	1,725,097	2,546,256	2,250,000	1,100,983	27,728,759	1,154,204	1,179,709
Proceeds from Suburban Undergrounding	417,227	601,652	691,417	924,094	1,133,396	1,221,143	1,283,619	1,349,291
Operating Fees and Grants	1,695,506	1,813,009	300,000	115,000				
O&M Cash Expenses net of Current Year Accruals	9,218,102	(224,598)	(5,587,831)	(1,488,877)	(6,677,240)	(2,117,270)	(1,768,314)	(1,533,539)
Non-Cash Power Expenses net of Revenue	2,861,440	155,742	668,787	1,252,654	1,584,598	1,670,275	1,721,383	1,783,550
Total	**18,321,864**	**7,391,442**	**2,773,687**	**13,146,528**	**10,809,932**	**44,301,748**	**17,810,889**	**18,575,093**
Minus City Taxes	**33,709,652**	**38,968,633**	**41,432,213**	**43,251,102**	**45,554,770**	**45,374,993**	**49,400,604**	**52,111,183**
Minus Amortization								
BPA Payments for Conservation	(5,963,898)	(6,550,860)	(10,948,027)					
High Ross Amortization	347,404	347,404	347,404	347,404	347,404	347,404	347,404	347,404
Conservation	12,152,631	13,356,303	14,449,768	16,086,175	17,925,292	19,739,197	21,491,577	23,182,697
Vehicles and Boats	2,112,060	2,163,750	2,214,095	2,266,457	2,320,020	2,375,439	2,432,655	2,491,553
Relicensing Mitigation	1,355,465	1,465,557	1,597,494	3,838,916	4,454,942	5,054,906	6,290,825	7,222,052
Puget Stillwater Sub	99,286	99,286	99,286	99,286	99,286	99,286	99,286	99,286
Puget Intertie								
Total	**10,102,948**	**10,881,440**	**7,760,020**	**22,638,238**	**25,146,944**	**27,616,232**	**30,661,747**	**33,342,992**
Minus Depreciation								
Production Plant	12,965,872	12,985,637	13,045,609	13,375,783	13,537,708	13,633,599	13,964,631	14,526,685
Transmission Plant	3,825,536	5,316,146	7,033,955	6,933,106	6,781,682	6,629,811	6,479,234	6,331,729
Distribution Plant	47,219,130	47,265,057	46,624,070	49,620,268	52,539,423	55,006,017	58,079,674	61,239,236
General Plant	16,681,994	17,791,317	18,752,858	23,164,360	26,985,862	28,404,071	25,804,192	16,778,660
ARO	753							
Total	**80,693,284**	**83,358,157**	**85,456,491**	**93,093,516**	**99,844,675**	**103,673,497**	**104,327,731**	**98,876,309**
equals								
Net Operating Revenue	**58,972,293**	**60,478,243**	**119,347,146**	**139,452,440**	**159,942,519**	**135,834,169**	**170,733,656**	**178,753,506**
Minus Interest Expense								
1st-Lien Bonds	72,918,915	75,830,089	79,730,194	86,709,543	92,436,806	97,402,366	98,538,491	99,574,489
2nd-Lien Bonds	20,451							
Bank Notes		33,121						
AFUDC on Projects	(3,833,222)	(5,201,573)	(6,663,123)	(7,293,919)	(8,939,741)	(11,866,403)	(10,916,205)	(10,216,747)
Total	**69,106,143**	**70,661,638**	**73,067,071**	**79,415,624**	**83,497,065**	**85,535,963**	**87,622,286**	**89,357,742**
Minus Amortization of Debt Expense								
Amort of Debt Issue Charges	1,225,344	1,077,302	1,072,463	990,038	888,077	819,021	765,962	717,651
Amort of Discount on Debt Issued	(3,361,452)	(61,716)	8,356,158	6,375,527	4,895,539	3,830,647	3,035,007	2,407,119
Amort of Charge on Refunded Debt	4,576,532	5,544,208	7,176,802	7,012,037	6,867,199	6,712,986	6,260,991	6,045,406
Total	**2,440,424**	**6,559,794**	**16,605,422**	**14,377,603**	**12,650,816**	**11,362,654**	**10,061,960**	**9,170,176**
Plus								
Investment Income	**2,612,978**	**3,250,621**	**4,427,862**	**10,372,915**	**13,954,058**	**16,091,466**	**15,719,543**	**16,102,713**
Gains(Loss) on Sale of Property	**28,921**	**718,790**	**2,546,256**	**2,250,000**	**1,100,983**	**46,928,759**	**1,154,204**	**1,179,709**
Other Income(Expense) Net	**(1,012,961)**	**104,426**	**(272,805)**	**(279,258)**	**(285,863)**	**(292,625)**	**(299,546)**	**(306,631)**
Fees, Grants, and Transfers								
Suburban Undergrounding	1,320,637	5,893,000	11,597,000	2,595,000	2,117,000	2,163,000		
Contributions in Aid of Construction-Cash	15,020,691	21,634,601	24,660,093	18,970,023	21,304,640	20,302,978	20,374,010	34,727,236
Contributions in Aid of Construction-Non-Cash	19,559,652	10,133,195	10,315,000	10,509,000	10,726,000	10,961,000	11,220,000	11,493,000
Capital Grants from Sound Transit	2,592,491	763,000	2,119,000	381,000	704,000	950,000	1,817,000	2,772,000
Capital Grants from FEMA	293,650							
Other Capital Fees and Grants	7,512,482	492,803	96,000	101,000	110,000	112,000	115,000	117,000
Operating Grants	1,695,506	1,813,009	300,000	115,000				
Total	**47,995,109**	**40,729,607**	**49,087,093**	**32,671,023**	**34,961,640**	**34,488,978**	**33,526,010**	**49,109,236**
equals								
Net Income	**37,049,773**	**28,060,256**	**85,463,059**	**90,673,893**	**113,525,457**	**136,152,130**	**123,149,622**	**146,310,614**

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
1.05 - ASSETS AND LIABILITIES								
Assets								
Plant Investment less Depreciation	1,797,912,969	1,870,271,559	2,039,800,236	2,221,035,118	2,400,364,139	2,510,614,481	2,621,182,739	2,734,051,449
Deferred Conservation Expenditures	162,136,725	176,763,401	188,448,377	211,858,981	235,168,221	257,703,811	279,439,987	300,440,283
Customer Conservation Loans Outstanding								
Operating Cash Acct	32,694,670	56,756,517	118,393,986	97,017,797	65,890,728	69,782,765	63,303,876	72,259,658
Construction Cash Acct	0	51,331,574						
Debt Service Cash Acct	2,510,783	0	(0)	7,421,403	12,216,975	18,942,711	24,097,739	28,742,143
Other Restricted Cash	29,129,067	71,870,028	114,346,664	117,288,258	121,416,074	126,391,880	132,227,845	138,364,043
Interest Earning Cash Accounts	64,334,520	179,958,118	232,740,651	221,727,458	199,523,777	215,117,356	219,629,460	239,365,845
Accrued Unbilled Revenue	60,198,421	66,541,143	67,797,171	69,417,929	71,328,577	70,915,582	72,772,573	74,264,046
Accounts Receivable	65,929,153	80,139,730	80,275,697	78,342,404	77,792,611	76,568,528	70,150,231	68,792,921
Other Current Assets	1,332,143	1,311,377	1,311,377	1,311,377	1,311,377	1,311,377	1,311,377	1,311,377
Capitalized Env Relicensing/ESA	65,169,693	70,720,175	81,878,458	94,292,793	104,845,562	131,151,916	146,804,132	165,070,377
Deferred Debt Issue Expense	4,879,054	3,000,087	3,187,624	3,397,586	3,574,509	3,959,088	3,965,626	4,050,775
Deferred Power Costs Balance	93,562,147	103,394,919	112,150,848	120,906,777	129,662,706	138,418,635	147,174,564	155,930,493
Power Exchange Balance			0	0	0	0	0	0
Suburban Undergrounding Receivable	26,674,028	31,849,525	42,817,015	44,570,725	45,655,928	46,707,257	45,538,710	44,310,379
Other Assets	8,283,096	17,086,456	17,086,456	17,086,456	17,086,456	17,086,456	17,086,456	17,086,456
Total Assets	**2,376,539,493**	**2,645,418,222**	**2,911,875,641**	**3,128,329,336**	**3,330,695,594**	**3,513,936,217**	**3,669,437,586**	**3,849,056,132**
Liabilities								
Accumulated Net Earnings	824,253,645	851,564,383	934,481,186	1,022,905,079	1,135,329,553	1,205,352,924	1,327,348,343	1,472,479,248
BPA Payments for Conservation	18,488,811	11,063,046	4,847,709	4,847,709	4,847,709	4,847,709	4,847,709	4,847,709
1st-Lien Bonds	1,383,050,000	1,538,335,000	1,664,470,000	1,769,733,421	1,846,712,391	1,942,563,805	1,962,265,261	1,987,289,304
2nd-Lien Bonds								
Interest Payable on 1st-Lien Bonds	20,930,567	34,375,494	30,131,934	31,994,947	34,113,581	36,455,044	37,134,163	37,875,042
Interest Payable on 2nd-Lien Bonds								
Interest Payable on Other Bonds	(0)	(707)	(707)	(707)	(707)	(707)	(707)	(707)
Unamortized Bond Discounts (net)	24,956,718	81,648,128	90,004,286	96,379,813	101,275,352	105,105,999	108,141,006	110,548,125
Deferred Charge on Refunded Debt	(27,922,396)	(31,636,441)	(24,459,639)	(17,447,602)	(10,580,403)	(3,867,417)	2,393,574	8,438,980
Revenue Anticipation Note Payable								
Notes Payable - City Cash Pool								
Rate Stabilization Deferred Revenue		43,918,128	76,394,764	79,336,358	83,464,174	88,439,980	94,275,945	100,412,143
Other Liabilities	132,782,149	116,151,191	136,006,108	140,580,317	135,533,943	135,038,879	133,032,293	127,166,287
Total Liabilities	**2,376,539,493**	**2,645,418,222**	**2,911,875,641**	**3,128,329,336**	**3,330,695,594**	**3,513,936,217**	**3,669,437,586**	**3,849,056,132**
Outstanding 1st-Lien and 2nd-Lien Bonds	1,383,050,000	1,538,335,000	1,664,470,000	1,769,733,421	1,846,712,391	1,942,563,805	1,962,265,261	1,987,289,304
Total Outstanding Debt	1,383,050,000	1,538,335,000	1,664,470,000	1,769,733,421	1,846,712,391	1,942,563,805	1,962,265,261	1,987,289,304
Accumulated Equity	824,253,645	851,564,383	934,481,186	1,022,905,079	1,135,329,553	1,205,352,924	1,327,348,343	1,472,479,248
Total Capitalization	2,207,303,645	2,389,899,383	2,598,951,186	2,792,638,500	2,982,041,944	3,147,916,729	3,289,613,603	3,459,768,552
Debt as a Pct of Total Capitalization	**62.7%**	**64.4%**	**64.0%**	**63.4%**	**61.9%**	**61.7%**	**59.7%**	**57.4%**

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 1 . 0 6 Purchased Power Revenue and Expenses								
Revenue from Wholesale Power Sales								
Wholesale Revenues excl Hydro Opt Benefit	92,936,456	85,138,929	143,003,215	151,190,694	160,478,869	164,997,650	163,744,351	170,546,083
Booked Out Long Term Purchases	(4,285,996)	(4,288,268)	(5,089,762)	(5,185,643)	(5,292,283)	(5,408,624)	(5,536,160)	(5,671,201)
Total	88,650,460	80,850,661	137,913,453	146,005,050	155,186,585	159,589,026	158,208,191	164,874,882
Revenue from Other Power Sales								
BPA Conservation & Renewables Credit	2,497,809	2,486,316	1,864,737					
BPA Payments for Conservation	5,963,898	6,550,860	10,948,027					
Article 49 Sales to PO County	1,721,879	1,612,308	1,696,984	1,738,071	1,773,813	1,812,807	1,855,553	1,900,814
SMUD 10-year Contract Exchange Energy	3,905,162	6,016,436	6,558,152	8,233,243	9,638,132	9,896,171	10,130,222	10,378,791
Sale of Lucky Peak Output	13,032,309	9,256,959	11,378,799					
Capacity Sales	9,499,528	6,281,765	6,694,956	6,821,077	6,961,348	7,114,380	7,282,138	7,459,768
Green Tag Sales		697,565	4,000,000	644,267	1,014,720	1,420,608		
BC Hydro 7-Mile Encroachment	499,085	526,209	585,900	831,200	831,766	902,956	957,640	1,019,660
Reserve Capacity & Reserve Energy	4,948,436	4,956,721	4,948,436	2,474,218	2,525,099	2,580,608	2,641,459	2,705,891
Sales from Priest Rapids	5,355,327	6,398,276	8,200,000	9,500,000	11,163,501	11,277,713	11,401,893	11,566,244
Seasonal Interchange Delivered	(1,601,096)	1,367,569	3,786,233	4,409,148	5,253,209	5,369,567	5,504,993	5,631,589
Transmission Losses Returned to BPA	5,468,158	5,299,653	5,225,496	5,323,934	5,433,418	5,552,861	5,683,798	5,822,441
Basis Sales	11,520,145	10,209,572	10,666,560	13,610,565	16,223,165	16,587,193	16,981,185	17,392,575
Other Services Revenue	1,659,245	545,382	913,550	930,759	949,900	970,781	993,673	1,017,911
Encroachment on Box Canyon	96,162	1,098,837	1,540,106	1,569,119	1,601,387	1,636,590	1,675,181	1,716,043
Close-out of Exchange Balances & FV adjustments	442,852	2,417,892	(965,767)	(1,842,866)	(2,103,837)	(2,246,584)	(2,320,752)	(2,365,974)
Total	65,008,900	65,722,320	78,042,170	54,242,734	61,265,620	62,875,652	62,786,984	64,245,754
Expense for Wholesale Power Purchases	24,570,643	34,239,862	32,503,215	49,090,694	56,779,682	58,304,537	60,204,132	62,963,828
Power-Related Wholesale Purchases								
Basis Purchases	10,794,066	9,350,091	9,572,160	12,495,549	15,085,219	15,424,231	15,790,801	16,173,154
Lucky Peak Exchange Energy Received	8,850,768	10,611,913	10,612,209					
Shaping	6,129,522	2,369,681	2,794,114	2,846,750	2,905,292	2,969,159	3,039,173	3,113,306
Other Services Purchases	2,906,880	3,566,414	3,708,895	3,778,763	3,856,472	3,941,249	4,034,184	4,132,588
Total	28,681,236	25,898,098	26,687,379	19,121,063	21,846,982	22,334,639	22,864,157	23,419,048
Deferred Power Expenses								
Expenses for Other Power Purchases								
Bonneville Power Administration(*)	153,685,459	163,358,315	159,945,097	157,935,355	160,042,300	165,537,485	169,271,474	179,369,250
Priest Rapids	1,788,917	9,270,080	11,900,000	13,100,000	3,385,555	3,749,424	3,923,318	4,249,047
High Ross Contract	13,057,920	13,043,136	13,080,667	13,088,767	13,095,843	13,103,563	13,112,026	13,120,987
Amortization of High Ross Contract	347,404	347,404	347,404	347,404	347,404	347,404	347,404	347,404
Grand Coulee	5,010,391	5,130,809	5,123,000	5,169,000	5,275,298	5,391,264	5,518,390	5,652,996
Lucky Peak	5,654,794	5,235,079	5,966,670	6,189,769	6,317,058	6,455,926	6,608,156	6,769,345
SPI Purchase	917,724	2,082,341	2,421,544	2,463,817	2,514,484	2,569,760	2,630,355	2,694,515
SMUD 10-Year Contract Exch Energy	4,505,646	5,265,896	4,995,245	6,453,980	7,667,933	7,835,596	8,020,399	8,237,835
Wind Resources	19,015,418	16,946,027	16,293,950	16,293,950	16,293,950	16,293,950	16,293,950	16,293,950
Integration Exchange of Wind Resources		2,271,494	5,421,156	8,921,640	9,105,108	9,305,267	9,524,686	9,757,018
IRP Resources	436,102		3,520,000	7,027,749	14,419,693	19,597,777	24,930,171	30,678,325
Columbia Ridge	71,997	2,747,876	2,816,200	2,880,300	2,939,532	3,004,151	3,074,989	3,149,995
Seasonal Interchange Received	194,674	2,102,723	4,534,436	5,817,947	6,928,437	7,083,031	7,250,050	7,430,446
Transmission Losses Returned to BPA (Expense)	5,468,158	5,299,653	5,225,496	5,323,934	5,433,418	5,552,861	5,683,798	5,822,441
BPA Credit for South Fork Tolt	(3,429,444)	(3,435,756)	(3,462,462)	(3,382,347)	(3,451,903)	(3,527,786)	(3,610,971)	(3,699,051)
Subtotal	206,725,159	229,665,076	238,128,403	247,631,265	250,314,110	262,299,674	272,578,195	289,874,503
(*) includes Residential Exchange Credit								
Booked Out Long Term Purchases	(4,285,996)	(4,288,268)	(5,089,762)	(5,185,643)	(5,292,283)	(5,408,624)	(5,536,160)	(5,671,201)
Total	202,439,163	225,376,807	233,038,641	242,445,622	245,021,827	256,891,050	267,042,035	284,203,301
Exchange Expense(Revenue), Net	1,352,918	(1,682,739)	1,713,970	3,251,666	3,779,065	3,960,048	4,065,809	4,164,831
Receivable/Payable into Power Market	64,079,816	46,610,798	105,410,238	96,914,356	98,406,904	101,284,489	98,004,059	101,911,054

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 1.06c Cash Flow Power Report								
Cash from Wholesale Power Sales, Net								
Wholesale Power Revenue Gross of Bookouts	92,936,456	85,138,929	143,003,215	151,190,694	160,478,869	164,997,650	163,744,351	170,546,083
Wholesale Power Purchases Gross of Bookouts	(24,570,643)	(34,239,862)	(32,503,215)	(49,090,694)	(56,779,682)	(58,304,537)	(60,204,132)	(62,963,828)
Total	68,365,812	50,899,067	110,500,000	102,100,000	103,699,187	106,693,113	103,540,219	107,582,255
Cash from Power Contracts								
Article 49 Sales to PO County	1,721,879	1,612,308	1,696,984	1,738,071	1,773,813	1,812,807	1,855,553	1,900,814
Sales from Priest Rapids	5,355,327	6,398,276	8,200,000	9,500,000	11,163,501	11,277,713	11,401,893	11,566,244
BPA Credit for South Fork Tolt	3,429,444	3,435,756	3,462,462	3,382,347	3,451,903	3,527,786	3,610,971	3,699,051
BPA Conservation & Renewables Credit	2,497,809	2,486,316	1,864,737					
BPA Residential Exchange Credit	10,914,704	5,982,756	5,982,756	5,982,756	5,982,756	5,982,756	4,487,067	
Total	23,919,163	19,915,412	21,206,939	20,603,174	22,371,974	22,601,062	21,355,484	17,166,110
Cash from Power Marketing, Net								
Power Marketing Revenue								
Sale of Lucky Peak Output	4,415,100	1,500,000	1,500,000					
Shaping	2,468,373	2,826,538	2,877,281	2,931,484	2,991,768	3,057,536	3,129,633	3,205,973
Parking	245,586	658,376	670,195	682,820	696,862	712,181	728,974	746,756
Green Tag Sales		697,565	4,000,000	644,267	1,014,720	1,420,608		
BC Hydro 7-Mile Encroachment	499,085	526,209	585,900	831,200	831,766	902,956	957,640	1,019,660
Reserve Capacity & Reserve Energy	4,948,436	4,956,721	4,948,436	2,474,218	2,525,099	2,580,608	2,641,459	2,705,891
Basis Sales	6,621,703	1,875,660	5,712,483	7,289,147	8,688,326	8,883,281	9,094,284	9,314,604
Other Services Revenue	141,642	(124,731)	101,795	103,713	105,846	108,172	110,723	113,424
Total	19,339,926	12,916,337	20,396,090	14,956,848	16,854,386	17,665,343	16,662,714	17,106,309
plus								
Transmission Revenue	1,773,144	3,102,182	2,189,204	2,231,471	2,277,360	2,327,423	2,382,304	2,440,415
minus								
Power Marketing Purchases								
Basis Purchases	5,876,160	1,009,697	4,618,083	6,174,130	7,550,380	7,720,320	7,903,900	8,095,183
Other Services Purchases	78,215	2,741,546	2,759,460	2,811,443	2,869,259	2,932,334	3,001,479	3,074,693
Total	5,954,375	3,751,243	7,377,543	8,985,574	10,419,639	10,652,654	10,905,379	11,169,876
Total	15,158,695	12,267,277	15,207,751	8,202,745	8,712,107	9,340,112	8,139,640	8,376,847
Cash to Power Contracts								
Long-term Purchased Power								
Bonneville Power Administration(*)	164,600,163	169,341,071	165,927,853	163,918,111	166,025,056	171,520,241	173,758,541	179,369,250
Priest Rapids	1,788,917	9,270,080	11,900,000	13,100,000	3,385,555	3,749,424	3,923,318	4,249,047
High Ross Contract	13,057,920	13,043,136	13,080,667	13,088,767	13,095,843	13,103,563	13,112,026	13,120,987
Grand Coulee	5,010,391	5,130,809	5,123,000	5,169,000	5,275,298	5,391,264	5,518,390	5,652,996
Lucky Peak	5,654,794	5,235,079	5,966,670	6,189,769	6,317,058	6,455,926	6,608,156	6,769,345
SPI Purchases	917,724	2,082,341	2,421,544	2,463,817	2,514,484	2,569,760	2,630,355	2,694,515
Wind Resources	19,015,418	16,946,027	16,293,950	16,293,950	16,293,950	16,293,950	16,293,950	16,293,950
Integration and Exchange of Wind Resources		2,271,494	5,421,156	8,921,640	9,105,108	9,305,267	9,524,686	9,757,018
IRP Resources	436,102		3,520,000	7,027,749	14,419,693	19,597,777	24,930,171	30,678,325
Columbia Ridge	71,997	2,747,876	2,816,200	2,880,300	2,939,532	3,004,151	3,074,989	3,149,995
Total	210,553,425	226,067,912	232,471,040	239,053,103	239,371,578	250,991,324	259,374,582	271,735,428
plus	(*) Excludes Residential Exchange Credit							
Water for Power								
Water for Power	8,499,379	10,683,743	12,025,307	12,597,373	13,589,888	14,681,029	15,881,000	17,197,562
Encroachment on Box Canyon (when energy delivered)	(96,162)	(1,098,837)	(1,540,106)	(1,569,119)	(1,601,387)	(1,636,590)	(1,675,181)	(1,716,043)
Total	8,403,217	9,584,906	10,485,201	11,028,255	11,988,501	13,044,439	14,205,818	15,481,519
plus								
Wheeling Purchases	38,401,416	39,697,156	39,873,009	39,210,070	40,112,878	41,093,581	42,163,611	43,295,387
Total	257,358,058	275,349,974	282,829,250	289,291,427	291,472,957	305,129,344	315,744,011	330,512,334

TABLE 1.08 Expected Energy Required / Supplied

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Expected Energy Disposed								
Seattle System Load	9,857,366	9,833,727	10,013,905	10,188,947	10,240,310	10,316,796	10,393,504	10,498,243
Article 49 Sales to PO County	370,031	368,795	370,022	371,036	370,022	369,997	369,996	371,034
Encroachment on Box Canyon	36,744	16,018	40,166	40,272	40,166	40,165	40,164	40,272
Marketing Losses	57,399	121,686	157,048	157,490	157,265	157,292	157,271	157,499
Seasonal Exchange Delivered	378,943	363,402	383,927	90,580	90,580	90,729	91,269	90,814
Sales to Power Market	2,625,069	5,628,832	3,542,510	3,136,116	2,934,262	2,960,480	2,876,359	2,922,699
Total	13,325,552	16,332,459	14,507,578	13,984,440	13,832,607	13,935,459	13,928,563	14,080,561
Expected Energy Generated								
Ross	715,593	702,112	768,691	771,538	770,220	770,278	770,514	772,901
Diablo	706,512	733,407	749,796	750,698	748,233	748,144	748,439	751,135
Gorge	861,902	891,463	904,163	906,155	903,137	903,461	903,632	906,805
Boundary	3,061,404	3,044,314	3,810,504	3,847,410	3,848,568	3,845,724	3,843,975	3,852,943
CF/NH	82,944	68,043	86,923	86,958	86,923	86,923	86,923	86,958
South Fork Tolt	52,706	47,889	53,829	53,829	53,709	53,709	53,709	53,829
Total	5,481,060	5,487,228	6,373,907	6,416,588	6,410,791	6,408,239	6,407,192	6,424,571
Expected Energy Purchased								
Bonneville Power Administration	5,211,452	5,225,986	5,371,760	4,989,668	4,917,861	4,973,906	4,917,886	4,990,415
Priest Rapids	215,839	149,406	173,833	174,921	24,091	24,087	24,085	24,148
High Ross Contract	301,580	302,947	310,246	310,246	309,214	309,277	309,354	311,522
Grand Coulee	239,763	243,469	240,034	240,034	240,034	240,034	240,034	240,034
Lucky Peak	288,363	272,822	293,347	293,622	293,347	293,347	293,347	293,622
SPI Purchase	26,280	26,280	26,280	26,352	26,280	26,280	26,280	26,352
Wind Resources	362,677	344,051	371,144	372,167	371,153	371,233	371,125	372,049
Columbia Ridge		51,301	50,633	50,772	50,633	50,633	50,633	50,772
IRP Resources	50,633		32,000	61,000	128,000	170,667	213,333	256,000
Seasonal Exchange Received	353,444	317,034	376,000	129,657	128,940	129,710	129,710	130,517
Purchases from Power Market	794,460	3,911,935	888,394	919,413	932,263	938,048	945,585	960,558
Total	7,844,491	10,845,231	8,133,671	7,567,852	7,421,815	7,527,220	7,521,371	7,655,989
Energy to/from Power Market	1,830,609	1,716,897	2,654,116	2,216,703	2,001,999	2,022,432	1,930,774	1,962,141

TABLE 1.09 Production O & M

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Hydro Production								
535 Supervision and Engineering	671,996	424,056						
537 Hydraulic Costs (Excl Amort of Relicensing Mitigation)	1,938,684	782,082						
538 Electric Costs	1,202,407	512,264						
539 Miscellaneous	6,924,165	3,010,567						
541 Supervision and Engineering	425,428	160,612						
542 Structures	2,668,620	1,167,887						
543 Reservoirs, Dams and Waterways	964,033	239,227						
544 Electric Plant	2,933,894	1,234,813						
545 Miscellaneous	1,037,816	(2,395,292)	5,540,138	3,549,013	3,304,761	3,302,435	3,284,463	3,378,687
Amort of Relicensing Mitigation Expenditures	1,355,465	1,465,557	1,597,494	3,838,916	4,454,942	5,054,906	6,290,825	7,222,052
Expenses Not Yet Distributed		12,477,797	20,067,929	20,469,287	20,896,135	21,361,787	21,866,243	22,390,102
Total	20,122,507	19,079,570	27,205,561	27,857,216	28,655,838	29,719,128	31,441,530	32,990,841
Water for Power Expenses								
536 Water for Power	3,665,783	4,065,616	4,829,505	5,265,405	5,649,367	6,071,391	6,535,466	7,044,131
536 Encroachment (Cash Payment)	674,799							
536 Encroachment (Energy Delivered to PO County)	96,162	1,098,837	1,540,106	1,569,119	1,601,387	1,636,590	1,675,181	1,716,043
540 Rents	4,062,634	5,519,290	5,655,696	5,762,849	6,339,134	6,973,047	7,670,352	8,437,387
Total	8,499,379	10,683,743	12,025,307	12,597,373	13,589,888	14,681,029	15,881,000	17,197,562
Other Power Costs								
556 System Control and Dispatch	6,450,396	7,086,699	7,631,535	7,784,166	7,946,489	8,123,570	8,315,407	8,514,623
557 Other Energy Costs (excl GGas Mitig & REC Purchases)	1,418,402	1,656,037	1,831,423	1,868,052	1,907,006	1,949,502	1,995,540	2,043,348
557 Greenhous Gas Mitigation	389,746	639,329						
557 REC purchases	180,111	663,901	1,145,400	2,121,967	2,522,802	2,961,837	3,442,119	4,816,048
Total	8,438,655	10,045,966	10,608,358	11,774,184	12,376,297	13,034,909	13,753,066	15,374,019
Total Production Expenses	**37,060,541**	**39,809,279**	**49,839,227**	**52,228,774**	**54,622,023**	**57,435,067**	**61,075,596**	**65,562,422**
557 REC Purchases-IRP resources				644,267	1,014,720	1,420,608	1,864,548	3,200,000
557 REC purchases-GreenUp Program	180,111	593,273	1,145,400	1,477,700	1,508,082	1,541,229	1,577,571	1,616,048
557 REC purchases-Other		70,628						

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016

TABLE 1.10 Transmission & Wheeling Revenues and Expenses

	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
Revenue from Transmission Services								
Transmission Line Rentals								
Wheeling to North Mountain Substation	223,114	274,562	369,978	377,974	385,747	394,227	403,523	413,365
Other Wheeling Sales	1,494,678	2,797,670	1,791,968	1,825,725	1,863,270	1,904,230	1,949,132	1,996,677
BPA PSANI Revenue	31,650							
BPA 3rd AC Intertie Revenue Sharing	23,702	29,950	27,259	27,772	28,343	28,966	29,649	30,373
Total	1,773,144	3,102,182	2,189,204	2,231,471	2,277,360	2,327,423	2,382,304	2,440,415
Transmission w/o Wheeling Expenses								
560 Supervision and Engineering	2,086,752	530,396						
561 Load Dispatching	581,445	360,430						
562 Station Operation (excl amortization)	133,275	75,843	(0)	(0)	(0)	(0)	(0)	(0)
563 Overhead Lines	54,909	10,040						
564 Underground Lines	30,529	17,833						
566 Miscellaneous	610,038	220,435						
567 Rents	22,571	30,664						
568 Supervision and Engineering	681,064	375,775						
569 Structures	100,358	65,952						
570 Station Equipment	1,176,081	476,486						
571 Overhead Lines	2,777,284	1,132,762						
572 Underground Lines	19,874	4,393						
573 Miscellaneous	127,187	30,769						
Intertie Operation and Maintenance	464,310	545,243	754,273	762,290	777,966	795,068	813,816	833,667
Amortization of Puget Stillwater Sub	99,286	99,286	99,286	99,286	99,286	99,286	99,286	99,286
Expenses Not yet Distributed		4,087,257	8,713,645	8,909,431	9,109,322	9,314,537	9,525,445	9,741,866
Total	8,964,963	8,063,563	9,567,204	9,771,007	9,986,574	10,208,891	10,438,547	10,674,819
Wheeling Expenses								
BPA Firm Wheeling	35,339,544	35,546,774	35,687,621	36,163,432	36,907,114	37,718,441	38,607,839	39,549,575
South Fork Tolt	430,705	412,648	429,502	431,936	440,819	450,509	461,132	472,380
Grand Coulee (Local)	150,060	198,241	191,870	192,280	196,234	200,548	205,277	210,284
Lucky Peak (Local)	749,591	1,664,275	1,809,363	1,854,402	1,892,537	1,934,141	1,979,748	2,028,039
Wind Resources	1,260,185	1,410,552	1,309,290					
Power Market Purchases	169,506	95,125	24,000	24,000	24,494	25,032	25,622	26,247
Other Wheeling Purchases	301,825	369,540	421,363	544,020	651,681	764,911	883,993	1,008,862
Total	38,401,416	39,697,156	39,873,009	39,210,070	40,112,878	41,093,581	42,163,611	43,295,387

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 1 . 1 1 Distribution & Customer Accounting & Administration O & M								
Distribution Costs								
580 Supervision and Engineering	4,157,780	2,316,248						
581 Load Dispatching	2,635,197	1,526,670						
582 Station Operation	3,744,350	2,140,274						
583 Overhead Lines	79,522	32,716						
584 Underground Lines	1,181,928	694,829						
585 Street Lighting and Signals	2,884,317	965,811						
586 Meters	1,168,437	559,375						
587 Customers Installation (Excl waiver of Trouble Call Charge)	2,020,867	451,554						
588 Miscellaneous	18,793,883	9,577,272						
589 Rents								
590 Supervision and Engineering	574,669	306,371						
591 Structures	986,610	444,417						
592 Station Equipment	1,777,807	1,085,279						
593 Overhead Lines	9,621,378	3,644,631						
594 Underground Lines	5,268,785	3,002,990						
595 Line Transformers	544,734	854,533						
596 Street Lighting and Signals	1,536,202	664,768						
597 Meters	27,850	(786,735)	5,614,000	5,136,940	1,428,916	1,460,328	1,494,763	1,531,224
598 Miscellaneous		(1,316,386)						
Waiver of Trouble Call Charge	1,126	1,154	1,184	1,214	1,244	1,275	1,307	1,340
Expenses Not Yet Distributed		29,554,888	62,583,855	63,835,533	65,166,700	66,618,883	68,192,081	69,825,786
Total	57,005,441	55,720,660	68,199,039	68,973,687	66,596,860	68,080,486	69,688,151	71,358,351
Customer Accounting & Advisory								
901 Supervision and Engineering	130,379	1,040						
902 Meter Reading	3,321,290	1,921,953						
903 Customer Records	20,620,216	11,139,406						
904 Uncollectible Accounts (not incl Goal Seeking)	5,271,105	5,472,626	5,666,173	5,625,774	5,708,983	5,748,459	5,155,227	5,204,586
905 Miscellaneous Accounting	542,931	(582,636)						
907 Supervision of Assistance	357,933	111,066						
908 Customer Assistance (Net of Rate Relief)	3,149,311	1,760,361						
908 Rate Relief Administration	464,219	475,585	486,556	497,489	508,651	520,109	531,886	543,971
910 Miscellaneous Assistance	1,433,927	548,873						
930 General Advertising	370,478	131,811						
Expenses Not Yet Distributed		14,413,234	29,512,771	30,103,026	30,730,767	31,415,575	32,157,451	32,927,860
Total	35,661,790	35,393,318	35,665,499	36,226,289	36,948,401	37,684,143	37,844,564	38,676,417
Administration and General								
920 Salaries	58,982,136	28,382,049	115,000	115,000				
923 Outside Services	10,400,118	6,027,481	4,603,491	(1,190,533)	5,050,963	5,012,727	5,156,041	5,237,640
924 Property Insurance	659,774	584,095						
925 Injuries and Damages	19,759,139	2,688,142	1,200,000	1,200,000	1,200,000			
926 Unallocated Pensions and Benefits	(0)	(792,064)						
930 Research and Development	263,711	(1,217,001)						
931 Rents	5,855,171	4,168,610						
935 Maintenance of General Plant (excl Veh & Boats)	4,861,030	1,522,370						
935 Amortization of Vehicles and Boats	2,112,060	2,163,750	2,214,095	2,266,457	2,320,020	2,375,439	2,432,655	2,491,553
Expenses Not Yet Distributed		42,077,042	87,771,624	89,590,150	91,483,404	94,748,773	96,986,255	99,309,795
Deferred A&G (Credit)	(29,675,942)	(29,498,097)	(27,578,958)	(28,130,537)	(28,717,145)	(29,357,082)	(30,050,346)	(30,770,275)
Total	73,217,198	56,106,377	68,325,253	63,850,537	71,337,242	72,779,858	74,524,605	76,268,713

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 1 . 1 2 Taxes								
Revenue Tax Base								
Revenue From Energy Sales to Customers	545,110,850	625,925,230	661,558,897	697,903,733	734,409,595	731,772,078	799,956,461	831,368,659
Other Revenue	22,584,687	21,128,215	21,813,381	22,242,537	22,772,665	23,330,112	23,879,590	24,439,555
Contributions in Aid of Construction - Cash	15,020,691	21,634,601	24,660,093	18,970,023	21,304,640	20,302,978	20,374,010	34,727,236
Contributions in Aid of Construction - in Kind								
Total	582,716,228	668,688,046	708,032,371	739,116,293	778,486,900	775,405,168	844,210,062	890,535,449
Seattle City Taxes								
City Business Tax	45,571	8,920	12,319	12,799	13,286	13,791	14,315	14,859
City Occupation Tax	33,664,082	38,959,713	41,419,894	43,238,303	45,541,484	45,361,202	49,386,289	52,096,324
Total	33,709,652	38,968,633	41,432,213	43,251,102	45,554,770	45,374,993	49,400,604	52,111,183
State Taxes								
State Business Tax	120,245	103,143	114,997	119,482	124,023	128,735	133,627	138,705
State Public Utility Tax	21,289,853	24,345,868	25,776,768	26,908,416	28,341,750	28,229,556	30,734,480	32,421,012
Other State Taxes		2,177	5,434	5,646	5,860	6,083	6,314	6,554
Total	21,410,099	24,451,188	25,897,199	27,033,544	28,471,633	28,364,374	30,874,421	32,566,271
Other Taxes								
King County Surface Water Management Fees	372,915	439,366	144,377	144,377	144,377	144,377	144,377	144,377
Whatcom County Contract Pmts	895,620	1,069,260	937,679	959,407	981,638	1,004,384	1,027,657	1,051,470
Pend Oreille County Contract Pmts	1,666,605	1,171,832	1,563,485	1,608,078	1,490,142	1,528,537	1,567,435	1,608,095
Renton Business Tax		38	96	100	104	108	112	116
Payments to Concrete School District	101,150	99,526	120,522	123,472	126,511	129,771	133,073	136,525
Unallocated Social Security Tax		430,067						
Total	3,036,290	3,210,089	2,766,159	2,835,434	2,742,772	2,807,177	2,872,654	2,940,583
Payments to Franchises								
Payments to Shoreline		687,613	1,688,341	1,726,277	1,765,008	1,804,770	1,845,635	1,887,569
Payments to Burien		317,793	782,532	802,096	822,148	842,702	863,769	885,363
Payments to Lake Forest Park		111,521	274,609	281,474	288,511	295,724	303,117	310,695
Payments to Tukwilla		716,773	1,764,981	1,809,105	1,854,333	1,900,691	1,948,208	1,996,914
Payments to Sea-Tac		55,247	136,040	139,441	142,927	146,500	150,163	153,917
Payments to Franchises - Actuals	4,118,611	2,806,328						
Total	4,118,611	4,695,273	4,646,503	4,758,393	4,872,927	4,990,387	5,110,892	5,234,458
Total Taxes	**62,274,652**	**71,325,183**	**74,742,074**	**77,878,473**	**81,642,101**	**81,536,931**	**88,258,571**	**92,852,494**

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 1 . 1 3 Other Revenue, Other Income, Oper. Grants & Misc. Retail								
Other Revenue								
Late Payment Fees & Interest	3,822,947	4,024,072	3,706,548	3,794,205	3,883,873	3,976,647	4,072,432	4,171,032
Revenue From Damage	1,853,912	1,510,656	1,564,569	1,596,840	1,635,031	1,676,279	1,714,067	1,751,943
Other O&M Revenue	9,351,595	7,166,223	5,374,846	5,501,958	5,631,984	5,766,516	5,905,413	6,048,392
Rental Income	2,835,314	2,142,529	1,289,963	1,320,470	1,351,676	1,383,964	1,417,299	1,451,614
Construction Charges	709	5,180	10,750	11,004	11,264	11,533	11,811	12,097
Transmission Attachments & Cell Site	1,439,934	2,043,649	2,719,612	2,749,843	2,815,610	2,886,642	2,951,714	3,016,939
Class 1 Pole Attachments	1,172,294	1,331,397	1,400,339	1,434,232	1,468,534	1,505,582	1,539,522	1,573,541
Class 2 Pole Attachments		594,224	624,054	639,158	654,445	670,955	686,080	701,241
Account Change Fee	1,187,742	1,285,162	1,455,656	1,492,047	1,529,349	1,567,582	1,606,772	1,646,941
Water Heater Rentals		877,500	2,106,000	2,106,000	2,156,369	2,210,769	2,260,605	2,310,559
Miscellaneous Rentals	161,978	170,381	187,680	192,119	196,659	201,356	206,207	211,199
Reconnect Charges	311,160	248,343	248,395	254,269	260,278	266,496	272,915	279,522
Merchandising Revenue	190							
Revenues - Nonutility	446,911	103,682						
Miscellaneous Income		(374,781)	1,124,969	1,150,392	1,177,593	1,205,791	1,234,753	1,264,535
Total	22,584,687	21,128,215	21,813,381	22,242,537	22,772,665	23,330,112	23,879,590	24,439,555
Other Income(Expense), Net								
Less Penalties	106,000	(14,540)						
Less Payments from Low Income Acc	339,462	48,415	(272,805)	(279,258)	(285,863)	(292,625)	(299,546)	(306,631)
Less Exp For Civ Pol & Rel Act	6							
Miscellaneous Other Income(Expens	567,492	(132,547)						
Total	1,012,961	(98,672)	(272,805)	(279,258)	(285,863)	(292,625)	(299,546)	(306,631)
Fees and Grants Available for Debt Se								
Operating Grants for Conservation		300,000	115,000	115,000				
Operating Grants from Sound Transit	22,738							
Operating Grants from FEMA	409,016							
Other Operating Fees and Grants	1,263,751	1,513,009	185,000					
Total	1,695,506	1,813,009	300,000	115,000				
Miscellaneous Retail Revenues								
Distribution Capacity Charges	194,929	199,702	204,309	208,899	213,586	218,398	223,343	228,418
First Hill and University Dist Network Re	1,400,000							
Green Pwr Rev-Residential (44005)	164,764	167,184	317,487	370,401	378,018	386,328	395,438	405,084
Greenup Rev-Residential (44006)	741,848	811,776	1,169,773	1,420,438	1,449,649	1,481,517	1,516,451	1,553,441
Residential Community Solar (44007)			300,000	450,000	459,254	469,350	480,417	492,136
Residential- Total "Green" Revenue	906,612	978,960	1,787,259	2,240,839	2,286,921	2,337,195	2,392,306	2,450,661
Green Pwr Rev Non-Residential (44207)	6,494	6,557	12,513	14,599	14,899	15,227	15,586	15,966
Greenup Rev Non-Residential (44208)	456,755	505,655	720,227	874,562	892,546	912,167	933,676	956,451
Non-Residential Total "Green" Revenue	463,249	512,212	732,741	889,161	907,446	927,394	949,262	972,417
Power Factor Charges	2,549,841	2,612,936	2,525,406	2,745,629	2,812,512	2,880,829	2,950,806	3,022,482
Credits for Transformation	(325,719)	(333,658)	(341,956)	(350,236)	(358,604)	(367,657)	(375,941)	(384,251)
Total Misc Retail Revenues	5,840,350	4,637,468	5,591,671	6,434,764	6,579,069	6,731,473	6,891,658	7,058,229

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 2 . 0 1 Revenue from Energy Sales to Customers								
Revenue From All Retail Customers	**540,651,208**	**603,148,163**	**647,652,557**	**695,158,733**	**731,608,145**	**728,909,044**	**797,025,917**	**828,366,630**
Revenue from Residential Customers	192,051,778	210,391,620	226,492,453	240,784,373	255,292,427	251,689,104	269,679,846	277,408,443
Revenue from Non-Residential Customers	348,599,430	392,756,543	421,160,104	454,374,360	476,315,718	477,219,939	527,346,071	550,958,187
Revenue from Distribution Capacity Charge		83,209	204,309	208,899	213,586	218,398	223,343	228,418
Revenue from Green Power Residential	164,764	167,184	317,487	370,401	378,018	386,328	395,438	405,084
Revenue from Green Power Non-Residential	(0)	3,048	12,513	14,599	14,899	15,227	15,586	15,966
Revenue from Power Factor Charges		1,088,723	2,525,406	2,745,629	2,812,512	2,880,829	2,950,806	3,022,482
Credits for Transformation		(139,024)	(341,956)	(350,236)	(358,604)	(367,657)	(375,941)	(384,251)
Revenue from MWh, kW and BSC Charges ($)								
Residential Service (Regular)	188,118,935	205,905,410	221,560,383	235,532,700	254,914,409	251,302,776	269,284,408	277,003,360
Residential Service (Assisted)	3,768,080	4,319,026	4,614,584	4,881,272				
Small General Service	70,048,308	74,521,978	81,138,262	87,899,391	92,432,353	92,843,238	102,559,224	107,463,866
Medium General Service	125,344,662	143,790,907	151,525,315	163,951,099	172,292,843	172,950,151	190,492,750	199,478,578
Large General Service	83,676,868	94,614,700	103,873,873	111,967,924	117,308,214	117,491,358	130,127,558	135,905,662
High Demand General Service	57,991,151	65,713,904	68,424,176	73,291,143	76,449,059	76,196,611	85,019,431	88,363,152
Street and Flood Lights	11,538,441	13,079,097	13,798,204	14,645,913	15,150,857	14,991,785	16,333,314	16,864,314
Total	540,486,444	601,945,023	644,934,797	692,169,441	728,547,734	725,775,919	793,816,685	825,078,932
Average Rates on MWh, kW and BSC ($/MWh)								
Residential Service (Regular)	$64.72	$74.67	$79.61	$84.34	$87.56	$86.63	$93.79	$96.66
Residential Service (Assisted)	$26.38	$30.24	$32.23	$33.93				
Small General Service	$55.97	$64.38	$68.11	$71.92	$74.60	$73.81	$80.33	$82.72
Medium General Service	$52.21	$61.47	$64.12	$67.68	$70.21	$69.47	$75.44	$77.68
Large General Service	$52.86	$61.60	$64.39	$67.99	$70.54	$69.81	$76.39	$78.67
High Demand General Service	$46.42	$53.79	$55.88	$58.94	$61.15	$60.50	$67.07	$69.06
Street and Flood Lights	$121.46	$137.78	$145.46	$154.32	$160.21	$158.49	$173.39	$178.68
Total	$56.06	$65.02	$68.37	$72.15	$75.56	$74.71	$81.11	$83.46
Sales to Customers (GWh)								
Residential Service (Regular)	2,907	2,758	2,790	2,810	2,932	2,921	2,909	2,906
Residential Service (Assisted)	143	143	143	145				
Small General Service	1,252	1,157	1,191	1,222	1,239	1,257	1,276	1,298
Medium General Service	2,401	2,339	2,362	2,422	2,454	2,489	2,524	2,567
Large General Service	1,583	1,536	1,613	1,647	1,663	1,683	1,704	1,728
High Demand General Service	1,250	1,222	1,225	1,244	1,251	1,260	1,270	1,282
Street and Flood Lights	95	95	95	95	95	95	95	95
Total	9,630	9,250	9,420	9,585	9,633	9,706	9,778	9,877

RateStudy2010_08_20_Case_04	Year 2009	Year 2010	Year 2011	Year 2012	Year 2013	Year 2014	Year 2015	Year 2016
T A B L E 2 . 0 2 Other Customer Revenue Parameters								
Energy Sales by Type of Customer (GWh)	9,629.540	9,249.606	9,419.707	9,584.676	9,633.360	9,705.588	9,777.982	9,876.639
Residential Class	3,055.859	2,907.401	2,940.159	2,960.711	2,938.294	2,927.256	2,915.806	2,912.916
Commercial Class	5,306.692	5,145.549	5,277.653	5,414.008	5,486.984	5,568.722	5,649.364	5,747.713
Industrial Class	1,266.989	1,196.646	1,201.918	1,209.980	1,208.107	1,209.634	1,212.836	1,216.035
Industrial Class by Industry								
Food	53.399	49.192	47.946	46.725	45.007	43.414	41.877	40.515
Stone	311.464	300.052	305.303	310.851	313.199	315.726	318.348	321.935
Metals	484.346	464.341	469.503	475.108	475.560	476.309	476.951	479.113
Aero	256.526	227.107	219.699	214.394	209.797	207.778	207.376	203.766
Ship	18.044	17.078	17.100	17.080	16.874	16.683	16.493	16.354
Other Industry	143.210	138.875	142.367	145.822	147.671	149.725	151.792	154.351
Low Income Assistance								
Rate Discounts	5,359,961	6,114,504	6,581,448	7,064,615	7,471,911	7,500,897	8,260,971	8,671,982
Payments from Low Income Account	1,012,961	(104,426)	272,805	279,258	285,863	292,625	299,546	306,631
Trouble Calls	1,126	1,154	1,184	1,214	1,244	1,275	1,307	1,340
Account Change		37,121	37,327	38,260	39,217	40,197	41,202	42,232
Administration	464,219	475,585	486,556	497,489	508,651	520,109	531,886	543,971
Total	**6,838,267**	**6,523,937**	**7,379,320**	**7,880,836**	**8,306,886**	**8,355,103**	**9,134,912**	**9,566,156**
Regular Residential Customer Rate	63.38	73.27	73.88	73.50	73.50	73.50	64.80	64.80
Assisted Residential Customer Rate	25.76	29.53	29.83	29.45	29.45	29.45	27.17	27.17
Rate Difference	37.61	43.74	44.05	44.05	44.05	44.05	37.64	37.64

Appendix 2 - Rate Stabilization Account

In March 2010 the Seattle City Council adopted legislation (City Ordinance 123260) to create a $100 million Rate Stabilization Account (RSA). The account will provide a financial buffer against City Light's exposure to volatile wholesale revenue, helping to stabilize City Light's operating revenues. In fiscal quarters where actual wholesale revenues are less than planned, the shortfall will be made up by transfers from the RSA account into the operating account. In fiscal quarters where actual wholesale revenue is higher than planned, the surplus revenue will be transferred into the RSA. If the RSA balance falls below $90 million, a retail rate surcharge will be placed on energy sales until the fund returns to $100 million. If the RSA balance exceeds $125 million, the additional funds will be removed from the RSA and, subject to City Council approval, used to decrease retail rates, contribute to the capital program, defease existing debt, and/or put towards new or expanded operating programs.

Funding Sources

The RSA is being filled with a combination of funding sources. The balance in the contingency reserve fund ($25 million) was rolled into the RSA in June 2010. Other sources include retail rate surcharges and debt service savings realized from the refinancing of existing debt in 2010. Assuming that net wholesale revenue comes in as planned, the RSA is projected to be fully funded by July 2011. Table A2.1 (same as Table 9.1 in Chapter 9) contains the projected funding sources of the RSA. In 2011 the RSA surcharge is expected to be 4.5% in the first quarter, dropping to 3% in the second quarter and being removed in July after the fund reaches its targeted balance of $100 million. It is possible that actual wholesale revenue will be lower/higher than planned, resulting in the RSA surcharge being removed before or after the targeted date of July 1. The ending 2011 balance of the RSA is projected to be over the $100 million target due to interest earnings.

Table A2.1
Proposed Funding Sources for the RSA

	2010	2011
Existing Contingency Reserve	$25.0	$0.0
Rate Surcharge Revenue, net	16.0	10.6
Transfers from Operations	27.7	21.0
Interest Income	0.2	0.9
End of the Year Balance	**$68.9**	**$101.4**

Net Wholesale Revenue Planning Value

The RSA legislation specifies that a historical average of net wholesale revenue should be used for budgeting and rate setting purposes. Specifically, it states that the forecasted net wholesale revenue should be the historical average starting in the year 2002 and ending with the year two years prior to the year being forecast. Thus, the planned 2011 wholesale revenue value is the average of the period 2002-2009. Similarly, the 2012 planned wholesale revenue is the average from 2002-2010, where 2010 is a forecasted value. Table A2.2 shows the historical net wholesale revenue values. In addition, the RSA legislation also depicts the quarterly shaping of the annual average value, which is displayed in Table A2.3. The legislation also notes that a value besides the historical average can be used if "after consideration of additional information, the City Council determines that a different methodology is warranted."

Table A2.2
Net Wholesale Revenue Historical Values

Year	$ millions
2002 Actual	$ 89.6
2003 Actual	$ 113.4
2004 Actual	$ 113.6
2005 Actual	$ 87.4
2006 Actual	$ 140.1
2007 Actual	$ 137.3
2008 Actual	$ 134.4
2009 Actual	$ 68.2
2010 Estimate	$ 35.0
2002-9 Average	**$ 110.5**
2002-10 Average	**$ 102.1**

Table A2.3
Planned Net Wholesale Revenue Quarterly Spreads

Fiscal Quarter	% Spread of Annual Average
1	30%
2	35%
3	15%
4	20%

Surcharge Rules

As stated above, if the RSA balance drops below $90 million a retail rate surcharge will be placed on all retail energy sales (kWh). The RSA legislation draws out specific criteria for the RSA surcharge amounts. The surcharge for each retail customer is calculated using a percentage of the base rates for the appropriate rate class. The surcharge criteria states that a 1.5% surcharge will be placed in increments for every $10 million the RSA balance is below the $100 million target, with the maximum surcharge being 4.5%. That is, there will be three potential surcharges: 1.5%, 3.0% and 4.5%. Table A2.4 provides the specific detail of the surcharge criteria. When a specific surcharge amount is removed it is replaced by the next level of surcharge, until there is no longer any surcharge. If the RSA balance ever drops below $50 million, City Light (with City Council approval) will increase rates, decrease spending, identify additional sources of funding or a combination of these measures to bring the fund to $100 million within 12 months.

Table A2.4
RSA Surcharge Rules

Surcharge Placed	Surcharge Amount	Surcharge Removed
RSA < $90 million	1.5%	RSA ≥ $100 million
RSA < $80 million	3.0%	RSA ≥ $90 million
RSA < $70 million	4.5%	RSA ≥ $80 million

RSA surcharge revenue will be transferred to the RSA on a monthly basis. However, surcharges will only be examined and changed on a quarterly basis after any differences in planned to actual wholesale revenue are transferred between the RSA and the operating account. City Light will notify both the Mayor and the City Council whenever they intend to impose an RSA surcharge.

RSA Mechanics
At the end of every quarter, the actual quarterly wholesale revenue will be compared with the respective planned quarterly wholesale revenue. If the actuals are higher than planned, the difference will be transferred from the operating account into the RSA. If the actuals are lower than planned, the difference will be transferred from the RSA to the operating account. In addition, any interest earned on the RSA balance will be sequestered in the RSA account. After any transfers due to wholesale revenue and earned interest, the RSA balance will be examined and any surcharges will be adjusted in accordance with the surcharge criteria listed above. If the RSA balance is over $125 million, City light will notify the Mayor and City Council and propose a use of the excess funds.

Both RSA surcharge revenue and interest earned on the RSA balance will be deposited into the RSA on a monthly basis as soon as the information becomes available.

RSA Accounting
One of the major functions of the RSA is to stabilize City Light’s annual financial performance, specifically its debt service coverage. When wholesale revenue is below planned, funds transferred from the RSA will make up the difference. However, to stabilize debt service coverage, funds transferred from the RSA to the operating account must be available for coverage. As a result, funds that are transferred to the RSA must be counted as deferred revenue. This is because funds that are transferred from the RSA to the operating account (to supplement lower than planned net wholesale revenue) will be counted as revenue available for debt service coverage in the year in which they are transferred. Funds cannot be counted as revenue twice. Therefore, to ensure that funds transferred from the RSA will be available for coverage when they are withdrawn, they will be deferred and not counted in the calculation of debt service coverage in the year in which they are transferred from the operating account to the RSA.

All cash that is transferred will be treated as deferred revenue. This includes interest earnings, surcharge revenue net of taxes and any other transfers from the operating account. The one exception is the initial transfer of the $25 million contingency fund, which is not being deferred at this time.

Appendix 3 - City Light's Wholesale Revenue Forecast Model

City Light's forecast of net wholesale revenue recognizes the uncertainty in three elements that determine its value. These elements are: (1) energy sales to customers, (2) energy generated by hydro resources, and (3) wholesale energy market prices. Thus, the process used to create the forecast of net wholesale revenue produces a probability distribution. The average value is used when a single-point forecast is called for, 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. System 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. 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 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.

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.

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 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.

There is great variability in the amount of power that might be sold to the wholesale power market. City Light has some probability of being a net purchaser, though this probability is quite low, and there is also a potential for selling five million MWh or more.

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 these factors are water conditions and wholesale market prices for natural gas.

Water conditions are negatively correlated with market prices. The more water that is available, the greater the supply of hydro power and, for a 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 closely 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 are 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 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 first step used the annual average forward market gas price for the forecast year as reported by Platts.[10] 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 and light load hours of the corresponding month to obtain the expected 2010 electric prices for each of those 24 time periods.[11]

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.[12] 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 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[13] (WECC)

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[10] Platts is a division of the McGraw-Hill Companies. Platts is an independent data source, 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.

[11] 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.

[12] 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.

[13] 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

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.

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 1 through 4 illustrate the historical volatility of three variables considered here. Figure 1 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 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 3 presents Mid Columbia prices subsequent to that time period and illustrates that they remain quite volatile. Figure 4 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.

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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."

Figure 1
Natural Gas Prices

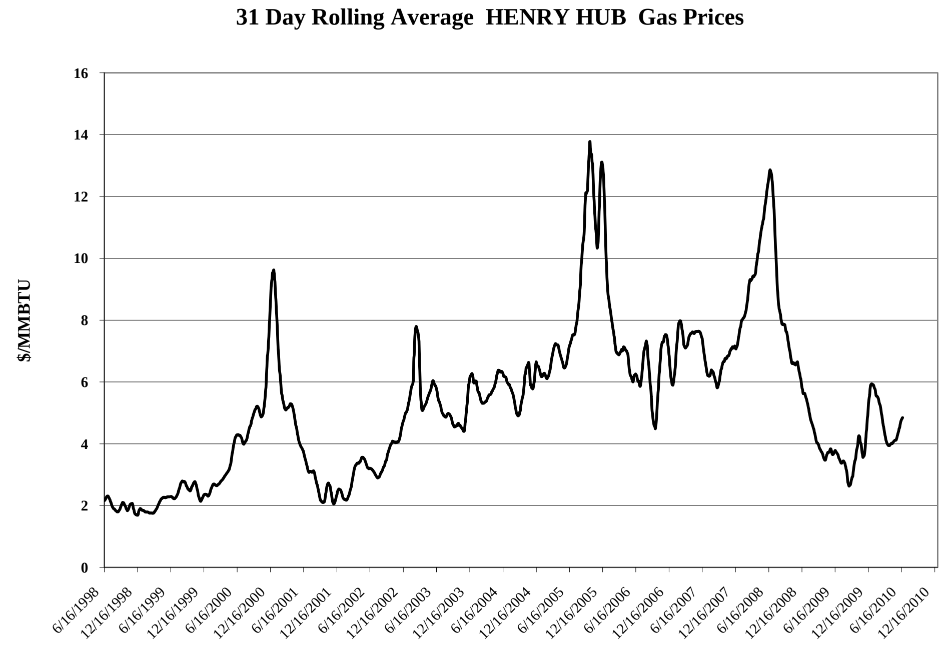


Figure 2
Long-Term Wholesale Electricity Prices

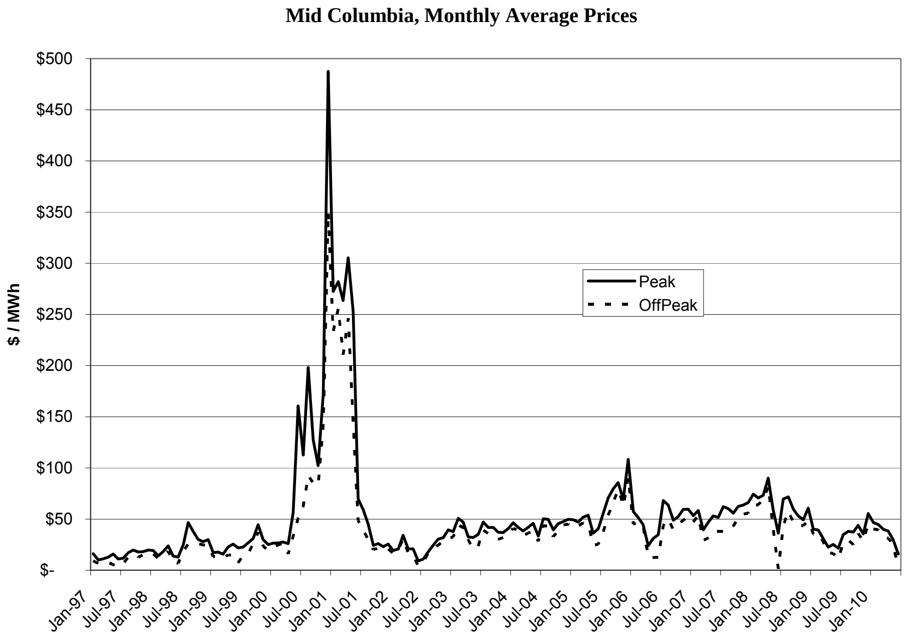


Figure 3
Mid-Term Wholesale Electricity Prices

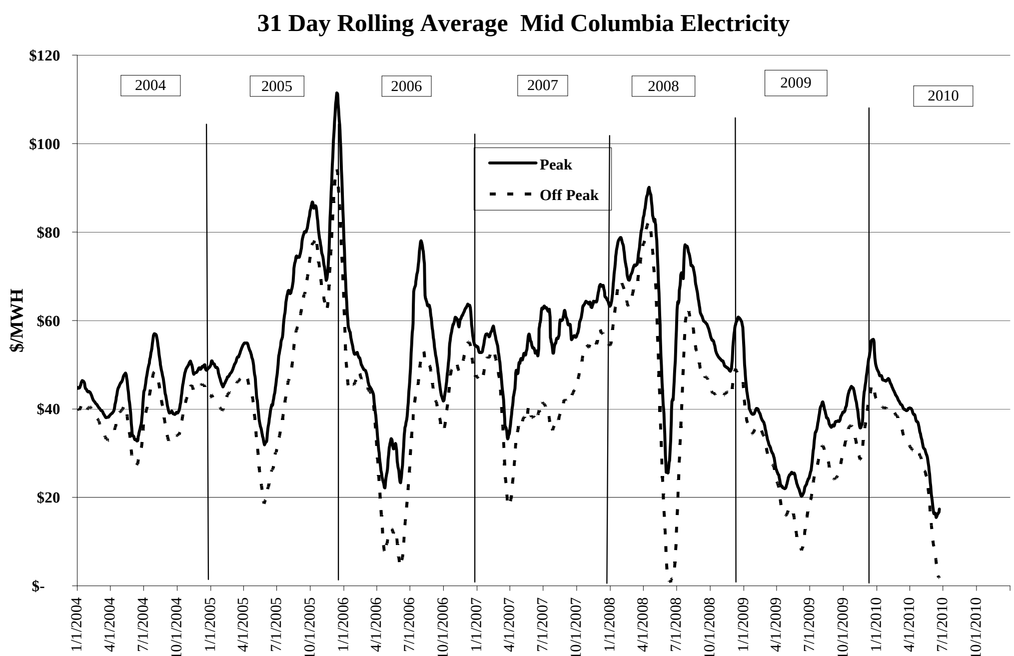
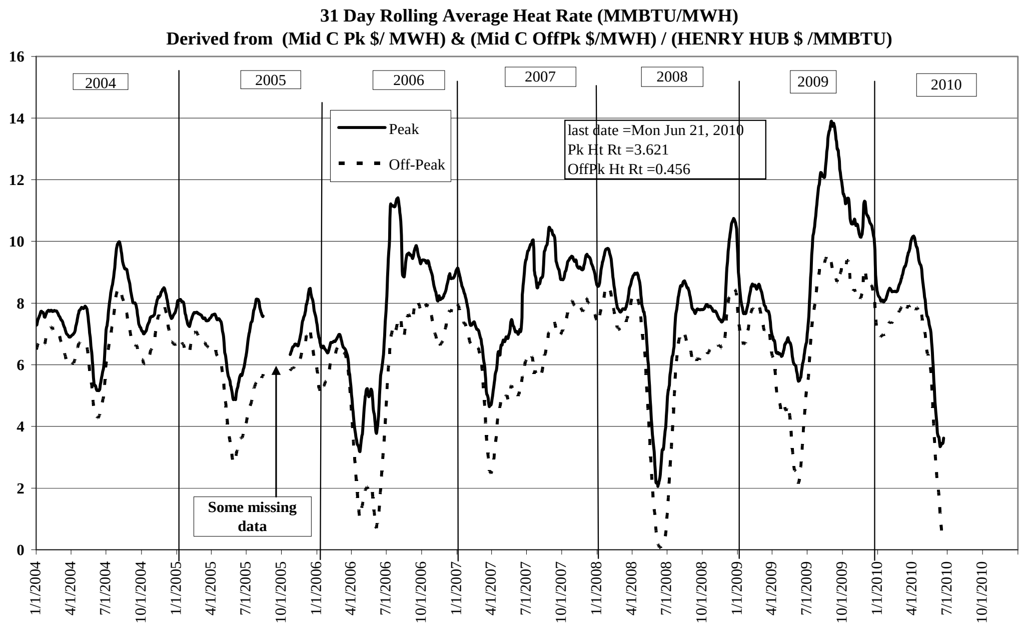


Figure 4
Market Heat Rate



Data about the intrinsic variability in these variables was used in the extensive modeling process described. Figures 5 through 7 present results of that modeling and illustrate potential outputs

Figure 5
Potential Natural Gas Prices, $/MMBTU, for 2011

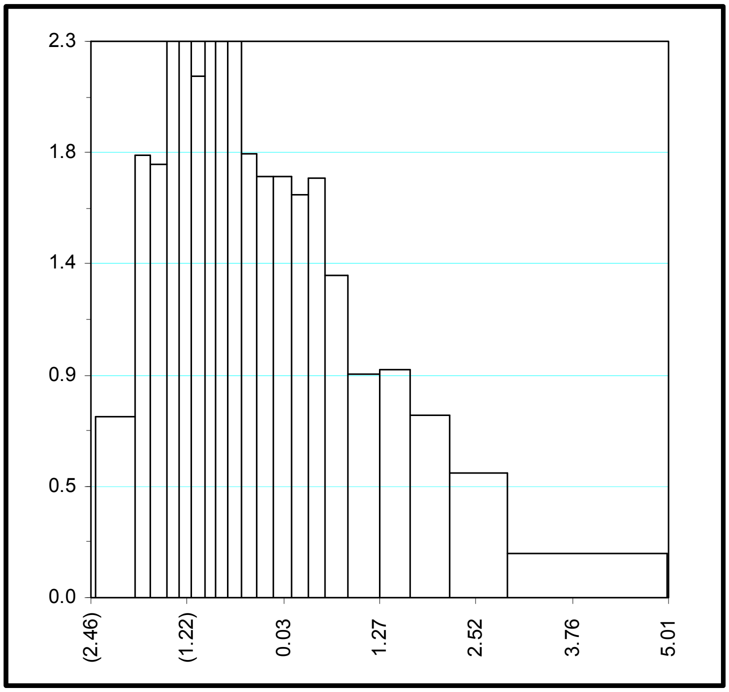
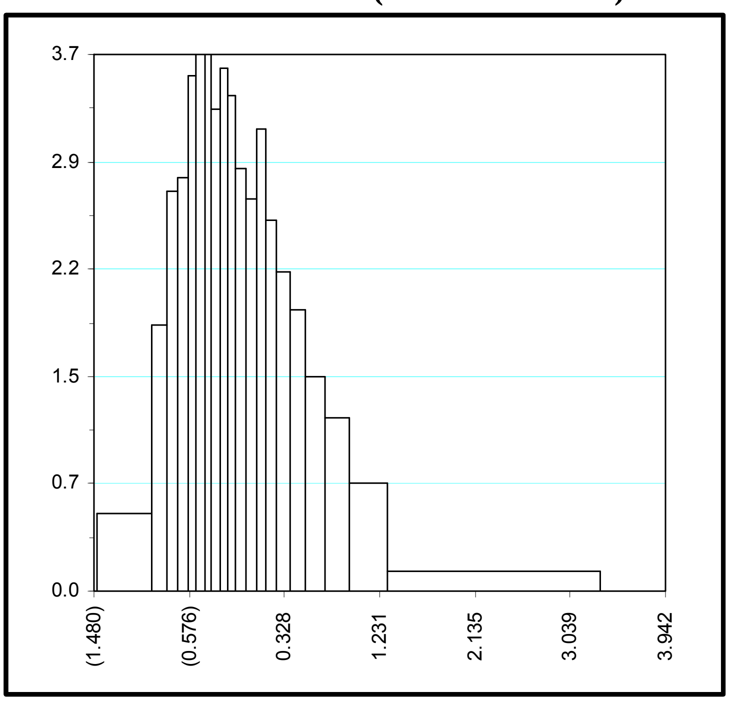


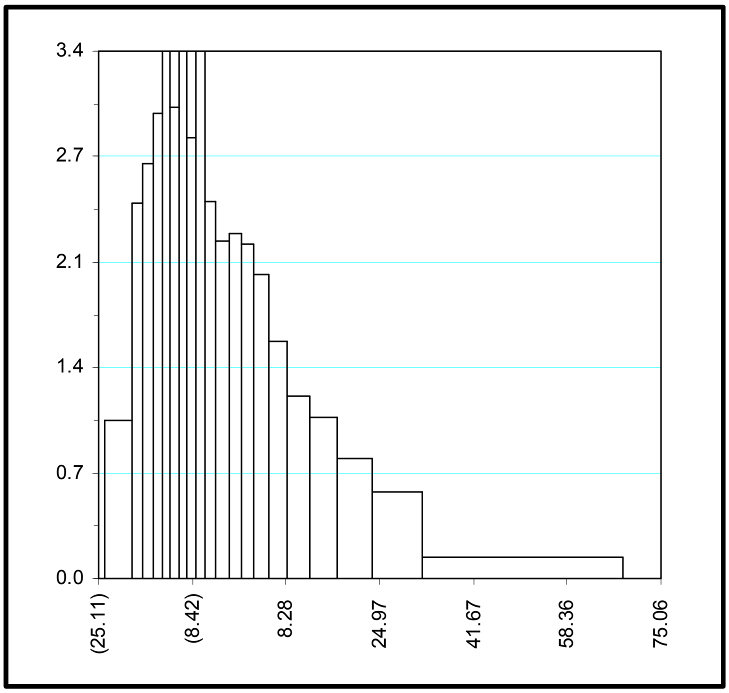
Figure 6
Potential Market Heat Rate (MMBTU / MWh) for 2011



for the year 2011 for natural gas prices, market heat rates and then wholesale electricity prices.

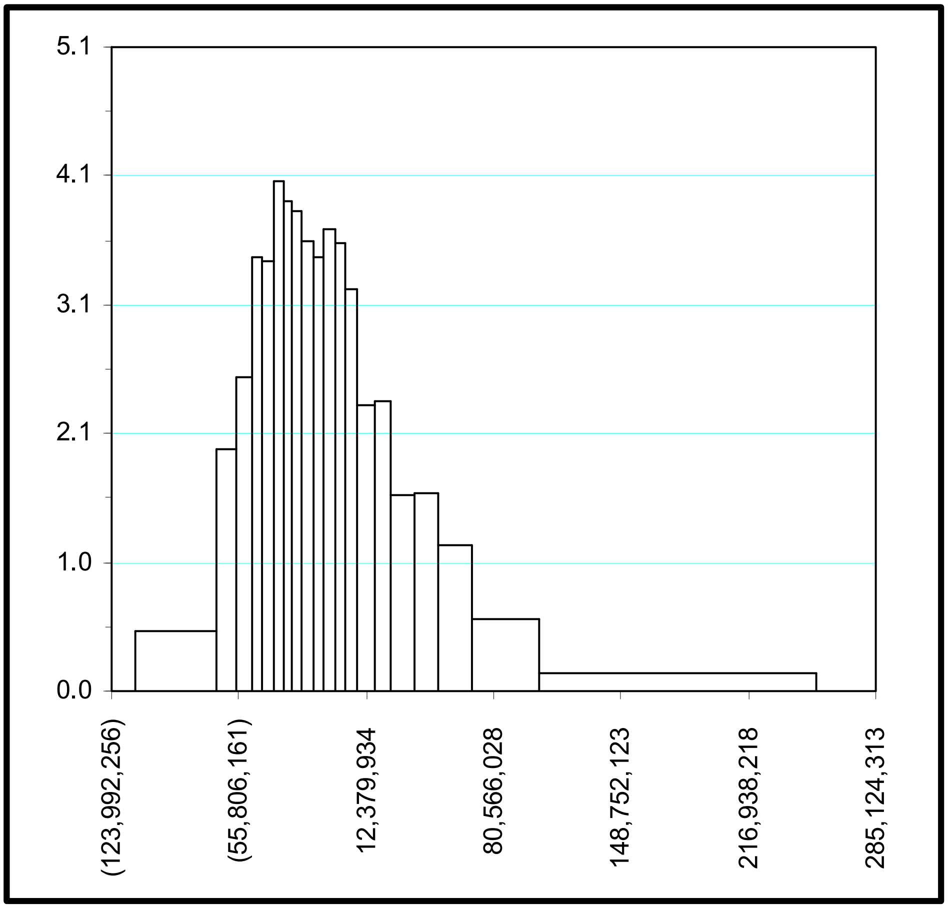
The bottom axis represents the variable and the vertical axis represents the probability density expressed in percent. The results have been scaled so that the sum of the areas of the 20 blocks (or bins) of data equal the length of the bottom axis. This last feature is for cosmetic purposes. The main point of each figure is an illustration 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.

Figure 7
Potential Wholesale Electric Energy Market Prices, $/MWh, for 2011



Wholesale prices interact with energy available to be sold to produce net wholesale revenue. Figure 8 illustrates the potential range of net wholesale revenue for the year 2011. The data 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.

Figure 8
Potential Net Wholesale Power Market Revenue (Expense) for 2011



Changing focus slightly from the probabilities of outcomes illustrated in the last four figures to the simple average of all the 2001 scenarios, there have been changes to loads and resources as estimated for the *2010 Rate Study* and this Rate Study. Table A3.1 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.

Summarizing the top two sections of Table A3.1, the projected system load for 2011 is up slightly (10.0 vs. 9.9 million MWh) because of the start of the anticipated economic upturn, which leaves slightly less energy available for wholesale sales. There is a similar increase in system load in 2012 so that, again, there is downward pressure on energy available for wholesale sales. City Light expects to receive less power from BPA in 2011 and, again, less in 2012 because a new contract becomes effective in October of 2011 that reduces the amount of power to be purchased from BPA. These declines reduce potential wholesale sales. However, more energy is expected to be generated from other resources, which makes more energy available for wholesale sales. The major increases are associated with Energy Exchanges. The average net amount of MWh to be sold on the wholesale market declines in 2011 from nearly 3.0 to 2.7

million MWh. A further decline to 2.2 million MWh is expected in 2012. See the bottom section of Table A3.1 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.

Table A3.1
Uses and Sources of City Light's Power

	Rate Study 2010	Forecast 2011	Change 2011 - 2010	Forecast 2012	Change 2012 - 2011
Uses of Power					
MWh of Electric Energy to Loads	14,633,136	14,507,578	(125,558)	13,984,440	(523,138)
Seattle System Load	9,919,004	10,013,905	94,901	10,188,947	175,042
Pend Oreille County	370,022	370,022	0	371,036	1,014
Encroachment	40,166	40,166	0	40,272	106
Energy Exchanges	383,561	383,927	366	90,580	(293,347)
Power Market for Losses	76,318	157,048	80,730	157,490	442
Power Market	3,844,065	3,542,510	(301,555)	3,136,116	(406,394)
Sources of Power					
MWh of Electric Energy from Resources	14,367,371	14,507,578	140,207	13,984,440	(523,138)
City Light Resources	6,271,819	6,373,907	102,088	6,416,588	42,681
Ross	751,587	768,691	17,104	771,538	2,846
Diablo	736,219	749,796	13,577	750,698	903
Gorge	883,690	904,163	20,473	906,155	1,991
Boundary	3,759,711	3,810,504	50,793	3,847,410	36,906
South Fork Tolt	53,829	53,829	0	53,829	0
Cedar Falls+Newhalem	86,783	86,923	140	86,958	35
Long Term Contracts	7,299,453	7,245,277	(54,175)	6,648,439	(596,838)
BPA, Slice+Block	5,639,596	5,371,760	(267,836)	4,989,668	(382,093)
High Ross	310,246	310,246	0	310,246	0
Lucky Peak	292,981	293,347	366	293,622	276
GCPHA	239,763	240,034	271	240,034	0
Priest Rapids	228,414	173,833	(54,581)	174,921	1,088
Wind Resources	402,844	371,144	(31,700)	372,167	1,023
SPI	26,280	26,280	0	26,352	72
Columbia Ridge	50,633	50,633	(0)	50,772	139
Energy Exchanges	108,696	376,000	267,304	129,657	(246,343)
Renewable Resource Acquisition	0	32,000	32,000	61,000	29,000
Spot Market Purchases					
Power Market	796,099	888,394	92,295	919,413	31,019
Cash from Wholesale Power Sales, Net	$119,973,371	$110,500,000	($9,473,371)	$102,100,000	($8,400,000)
MWh of Energy to Wholesales Power Sales, Net	3,047,966	2,654,116	(393,850)	2,216,703	(437,413)
Dollars per MWH of Energy to Power Market	$39.36	$41.63	$2.27	$46.06	$4.43
Dollars per MMBTU of Natural Gas	$5.34	$4.55	($0.79)	$6.33	$1.78
Ratio of Electric Energy Price to Natural Gas Price	7.37	9.14	1.77	7.27	(1.87)

Appendix 4 - Calculation of BPA Pass-through and Annual Average Rate with BPA Pass-through

Average rates charged to retail customers and changes in those rates are associated with all the financial costs and revenues that City Light faces, as well as its retail load. One of the largest single costs for City Light is payment for power from the Bonneville Power Administration (BPA). The City of Seattle passed an Ordinance that requires City Light to adjust its retail rates whenever BPA changes the rates it charges to City Light. This adjustment to retail rates is referred to as the BPA increment or BPA pass-through. For analytic purposes, therefore, it is useful to distinguish between changes in rates associated with changes in BPA rates and changes associated with all other causes.

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 expected to be higher than inflation. For planning purposes, City Light estimates that increase to be eight percent. Applying the required process to these rate changes, and converting the result to $/MWh, produces BPA pass-through adjustments for 2010 and 2011 of $0.30 and $1.20 per MWh, respectively. These pass-throughs are shown in Table S2 in the Summary.

The average system rate, starting in January 2011, after the rate change required to satisfy the revenue requirement of $651,516,246 that year, is computed with the assistance of forecasts of retail sales and knowledge of the next BPA pass-through. Total sales in 2011 are estimated to be 9,419,707 MWh with sales in the fourth (4^{th}) quarter when the 2011 BPA $1.20/MWh pass-through comes into effect expected to be 2,554,638 MWh. The average system rate after the BPA pass-through is then solved for as Revenue Requirement minus a product of BPA pass-through and energy sales in the 4^{th} quarter divided by total sales for the year.[14] Using this approach the **average system rate for 2011** is calculated as follows:

(651,516,246 – 1.20 * 2,554,638) / 9,419,707 = **$68.84.**

[14] 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 4^{th} quarter.

This average rate is an increase of $2.85 (= $68.84-$65.99) over the previous rate ($65.99) which included the $0.30/MWh BPA pass-through in October 2010, which equates to a 4.3% increase in the average system rate (i.e. $2.85 / $65.99 = 0.043 = 4.3%) for 2011 base rates.

Appendix 5 - 2011 and 2012 Proposed Retail and Area Lighting Rate Schedules (excludes RSA surcharges)

Residential	January 1, 2011		January 1, 2012	
Standard				
Seattle	**Schedule RSC**		**Schedule RSC**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0461	$0.0461	$0.0493	$0.0493
Second Block per kWh	$0.0956	$0.0956	$0.1009	$0.1009
Base Service Chrg per day	$0.1155	$0.1155	$0.1203	$0.1203
Tukwila	**Schedule RST**		**Schedule RST**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0527	$0.0527	$0.0561	$0.0561
Second Block per kWh	$0.1050	$0.1050	$0.1107	$0.1107
Base Service Chrg per day	$0.1155	$0.1155	$0.1203	$0.1203
Suburban	**Schedule RSS**		**Schedule RSS**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0495	$0.0495	$0.0528	$0.0528
Second Block per kWh	$0.0993	$0.0993	$0.1047	$0.1047
Base Service Chrg per day	$0.1155	$0.1155	$0.1203	$0.1203
Shoreline	**Schedule RSH**		**Schedule RSH**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0515	$0.0515	$0.0549	$0.0549
End Block per kWh	$0.1013	$0.1013	$0.1068	$0.1068
Base Service Chrg per day	$0.1155	$0.1155	$0.1203	$0.1203
	North City Undergrounding Charge:		North City Undergrounding Charge:	
	All kWh at $0.0007 per kWh		All kWh at $0.0007 per kWh	
	Aurora 1 Undergrounding Charge:		Aurora 1 Undergrounding Charge:	
	All kWh at $0.0017 per kWh		All kWh at $0.0017 per kWh	
Burien	**Schedule RSB**		**Schedule RSB**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0495	$0.0495	$0.0528	$0.0528
End Block per kWh	$0.0993	$0.0993	$0.1047	$0.1047
Base Service Chrg per day	$0.1155	$0.1155	$0.1203	$0.1203
	1st Ave S 1 Undergrounding Charge:		1st Ave S 1 Undergrounding Charge:	
	All kWh at $0.0037 per kWh		All kWh at $0.0037 per kWh	

Residential

Rate Assisted	January 1, 2011		January 1, 2012	
Seattle	**Schedules REC/RLC**		**Schedules REC/RLC**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0194	$0.0194	$0.0207	$0.0207
Second Block per kWh	$0.0355	$0.0355	$0.0375	$0.0375
Base Service Chrg per day	$0.0578	$0.0578	$0.0602	$0.0602
Tukwila	**Schedules RET/RLT**		**Schedules RET/RLT**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0224	$0.0224	$0.0239	$0.0239
End Block per kWh	$0.0394	$0.0394	$0.0416	$0.0416
Base Service Chrg per day	$0.0578	$0.0578	$0.0602	$0.0602
Suburban	**Schedules RES/RLS**		**Schedules RES/RLS**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0209	$0.0209	$0.0223	$0.0223
Second Block per kWh	$0.0370	$0.0370	$0.0391	$0.0391
Base Service Chrg per day	$0.0578	$0.0578	$0.0602	$0.0602
Shoreline	**Schedules REH/RLH**		**Schedules REH/RLH**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0218	$0.0218	$0.0233	$0.0233
End Block per kWh	$0.0380	$0.0380	$0.0401	$0.0401
Base Service Chrg per day	$0.0578	$0.0578	$0.0602	$0.0602
	North City Undergrounding Charge:		North City Undergrounding Charge:	
	All kWh at $0.0003 per kWh		All kWh at $0.0003 per kWh	
	Aurora 1 Undergrounding Charge:		Aurora 1 Undergrounding Charge:	
	All kWh at $.0007 per kWh		All kWh at $.0007 per kWh	
Burien	**Schedules REB/RLB**		**Schedules REB/RLB**	
Energy Charges	**Summer**	**Winter**	**Summer**	**Winter**
First Block per kWh	$0.0209	$0.0209	$0.0223	$0.0223
End Block per kWh	$0.0370	$0.0370	$0.0391	$0.0391
Base Service Chrg per day	$0.0578	$0.0578	$0.0602	$0.0602
	1st Ave S 1 Undergrounding Charge:		1st Ave S 1 Undergrounding Charge:	
	All kWh at $0.0015 per kWh		All kWh at $0.0015 per kWh	

Small General Service	January 1, 2011	January 1, 2012
	Schedule SMC	**Schedule SMC**
Seattle	**Year Round**	**Year Round**
Per kWh	$0.0669	$0.0710
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26
	Schedule SMT	**Schedule SMT**
Tukwila	**Year Round**	**Year Round**
Per kWh	$0.0714	$0.0757
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26
	Schedule SMS	**Schedule SMS**
Suburban	**Year Round**	**Year Round**
Per kWh	$0.0700	$0.0742
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26
	Schedule SMH	**Schedule SMH**
Shoreline	**Year Round**	**Year Round**
Per kWh	$0.0714	$0.0757
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26
	North City Undergrounding Charge:	North City Undergrounding Charge:
	All kWh at $0.0007 per kWh	All kWh at $0.0007 per kWh
	Aurora 1 Undergrounding Charge:	Aurora 1 Undergrounding Charge:
	All kWh at $0.0017 per kWh	All kWh at $0.0017 per kWh
	Schedule SIB	**Schedule SMB**
Burien	**Year Round**	**Year Round**
Per kWh	$0.0700	$0.0742
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26
	1st Ave S 1 Undergrounding Charge:	1st Ave S 1 Undergrounding Charge:
	All kWh at $0.0037 per kWh	All kWh at $0.0037 per kWh
	Schedule SMD	**Schedule SMD**
City Network	**Year Round**	**Year Round**
Per kWh	$0.0669	$0.0710
Minimum bill per meter per day	$0.27	$0.28
Transformer Investment	$0.25	$0.26

Medium General Service	January 1, 2011	January 1, 2012
	Schedule MDC	**Schedule MDC**
Seattle	**Year Round**	**Year Round**
Per kWh	$0.0569	$0.0606
Per kW	$1.22	$1.27
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26
	Schedule MDT	**Schedule MDT**
Tukwila	**Year Round**	**Year Round**
Per kWh	$0.0626	$0.0665
Per kW	$1.22	$1.27
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26
	Schedule MDS	**Schedule MDS**
Suburban	**Year Round**	**Year Round**
Per kWh	$0.0613	$0.0651
Per kW	$1.22	$1.27
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26
	Schedule MDH	**Schedule MDH**
Shoreline	**Year Round**	**Year Round**
Per kWh	$0.0624	$0.0663
Per kW	$1.22	$1.27
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26
	North City Undergrounding Charge:	North City Undergrounding Charge:
	All kWh at $0.0007 per kWh	All kWh at $0.0007 per kWh
	Aurora 1 Undergrounding Charge:	Aurora 1 Undergrounding Charge:
	All kWh at $0.0017 per kWh	All kWh at $0.0017 per kWh
	Schedule MDB	**Schedule MDB**
Burien	**Year Round**	**Year Round**
Per kWh	$0.0613	$0.0651
Per kW	$1.22	$1.27
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26
	1st Ave S 1 Undergrounding Charge:	1st Ave S 1 Undergrounding Charge:
	All kWh at $0.0037 per kWh	All kWh at $0.0037 per kWh
	Schedule MDD	**Schedule MDD**
City Network	**Year Round**	**Year Round**
Per kWh	$0.0669	$0.0710
Per kW	$1.89	$1.97
Minimum bill per meter per day	$0.71	$0.74
Transformer Investment	$0.25	$0.26

Large General Service	January 1, 2011	January 1, 2012
	Schedule LGC	**Schedule LGC**
Seattle	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0438	$0.0468
All kWh Peak at	$0.0648	$0.0687
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$33.15	$34.54
Transformer Investment	$0.25	$0.26
	Schedule LGT	
Tukwila	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0490	$0.0523
All kWh Peak at	$0.0727	$0.0770
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$33.15	$34.54
Transformer Investment	$0.25	$0.26
	Schedule LGS	**Schedule LGS**
Suburban	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0476	$0.0508
All kWh Peak at	$0.0705	$0.0747
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$33.15	$34.54
Transformer Investment	$0.25	$0.26
	Schedule LGH	**Schedule LGH**
Shoreline	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0485	$0.0518
All kWh Peak at	$0.0714	$0.0757
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$33.15	$34.54
Transformer Investment	$0.25	$0.26
	North City Undergrounding Charge:	North City Undergrounding Charge:
	All kWh at $0.0007 per kWh	All kWh at $0.0007 per kWh
	Aurora 1 Undergrounding Charge:	Aurora 1 Undergrounding Charge:
	All kWh at $0.0017 per kWh	All kWh at $0.0017 per kWh
	Schedule LGD	**Schedule LGD**
City Network	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0485	$0.0518
All kWh Peak at	$0.0720	$0.0763
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$1.99	$2.08
Minimum bill per meter per day	$33.15	$34.54
Transformer Investment	$0.25	$0.26

High Demand General Service	January 1, 2011	January 1, 2012
	Schedule HDC	**Schedule HDC**
Seattle	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0419	$0.0449
All kWh Peak at	$0.0618	$0.0656
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$141.03	$146.95
Transformer Investment	$0.25	$0.26
	Schedule HDT	**Schedule HDT**
Tukwila	**Year Round**	**Year Round**
All kWh Off-peak at	$0.0433	$0.0463
All kWh Peak at	$0.0641	$0.0680
All kW Off-Peak at	$0.25	$0.26
All kW Peak at	$0.95	$0.99
Minimum bill per meter per day	$141.03	$146.95
Transformer Investment	$0.25	$0.26
Power Factor Rate	**Schedule PF**	**Schedule PF**
	$0.0015	$0.0015
	per kVarh	
Reserved Distribution Capacity Charge		
	$0.24	$0.25
	per Monthly Max kW	per Monthly Max kW

Schedule F-Floodlights

	Rates Effective	January 2011 Rate	January 2012 Rate
Option E:	**Option E:**		
MFEE	200 Watt Sodium Vapor, 22,000 lumens	$5.95	$6.31
MFEM	400 Watt Sodium Vapor, 50,000 lumens	$12.34	$12.96
Option M:	**Option M:**		
MFGE	200 Watt Sodium Vapor, 22,000 lumens	$11.27	$11.94
MFGM	400 Watt Sodium Vapor, 50,000 lumens	$17.10	$18.02

Schedule T-Streetlights

	Rates Effective	January 2011 Rate	January 2012 Rate
Option M:	**Option M:**		
MTCM	100 Watt Sodium Vapor, 9,000 lumens	$6.98	$7.34
MTDC	150 Watt Sodium Vapor, 16,000 lumens	$11.49	$12.06
MTDM	200 Watt Sodium Vapor, 22,000 lumens	$8.46	$8.91
MTEC	250 Watt Sodium Vapor, 27,500 lumens	$12.72	$13.36
MTEM	400 Watt Sodium Vapor, 50,000 lumens	$9.51	$10.02

	Rates Effective	January 2011 Rate	January 2012 Rate
Option C:	**Option C:**		
MTFC	100 Watt Sodium Vapor, 9,000 lumens	$14.44	$15.19
MTFM	150 Watt Sodium Vapor, 16,000 lumens	$11.25	$11.86
MTGC	200 Watt Sodium Vapor, 22,000 lumens	$18.19	$19.16
MTGM	250 Watt Sodium Vapor, 27,500 lumens	$14.85	$15.68
MTIC	400 Watt Sodium Vapor, 50,000 lumens	$9.96	$10.44

Schedule P-Pedestrian Lights

	Rates Effective	January 2011 Rate	January 2012 Rate
Option M	**Option M:**		
MPBC	ZED47A 70 Watts	$13.85	$14.47
Option C:	Option C:		
MPBM	ZED47A 70 Watts	$7.39	$7.74
Option P:	**Option P:**		
MPBP	ZED47A 70 Watts	$40.99	$42.75