Revenue Requirements Analysis

Adopted 2015-2016 Rates

October 6, 2014

Seattle City Light

Contents

Executive Summary

S.1 Revenue Requirements

Table S1 shows the 2015 and 2016 Revenue Requirements and the respective annual changes. The revenue requirement shown here differs from the revenue requirement found in the COSACAR, which treats rate discounts as a cost for the purposes of cost allocation.

Table S1
Revenue Requirements

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Revenue Requirement	$755.5	$774.1	$815.6	$18.6	$41.5

S.2 Drivers of the Increase in Revenue Requirements

The drivers of the **$18.6 million** increase between 2015 and 2014 are:
Increases

- $7.8 million higher debt service coverage requirements
  - Higher debt service as a result of funding requirements for City Light's sizable capital program
- $20.0 million lower net wholesale revenue (NWR)
  - 2014 Strategic Plan Update endorsed further reducing NWR targets to levels even more conservative than the 2012 Strategic Plan
- $1.8 million increase to non-power direct O&M
  - Higher labor wages, benefit costs
  - Partially offset by $10M underspending assumption
- $1.6 million higher taxes, uncollectible revenue, and other miscellaneous expenses

Decreases

- $6.0 million decrease in power contract costs
  - Lower annual planning values used for BPA power and wheeling expenses
- $4.7 million increase in power revenues
  - Higher revenues from transmission sales and ancillary services
- $0.2 million decrease from other miscellaneous revenues
  - Higher Other Revenue
  - Lower interest earning on investments
- $1.8 million from the difference in the actual debt service coverage

The drivers for the **$41.5 million** change between 2016 and 2015 include:
Increases

- $19.2 million higher debt service coverage requirements
  - Higher debt service as a result of funding requirements for City Light's large capital program
- $6.4 million higher power contract costs

    - Higher BPA power and wheeling expenses
- $5.0 million lower planned NWR
    - Per the 2014 Strategic Plan Update
- $1.4 million higher taxes, uncollectible revenue, and other miscellaneous expenses
    - Mostly higher taxes from higher retail revenue
- $7.7 million increase to non-power direct O&M
    - Increased spending on Strategic Initiatives, baseline inflation
- $1.7 million decrease to power and other sources of revenue

Figure S1 gives a high-level graphical view of the 2015 and 2016 revenue requirement drivers.

Figure S1
High-Level Revenue Requirements Drivers

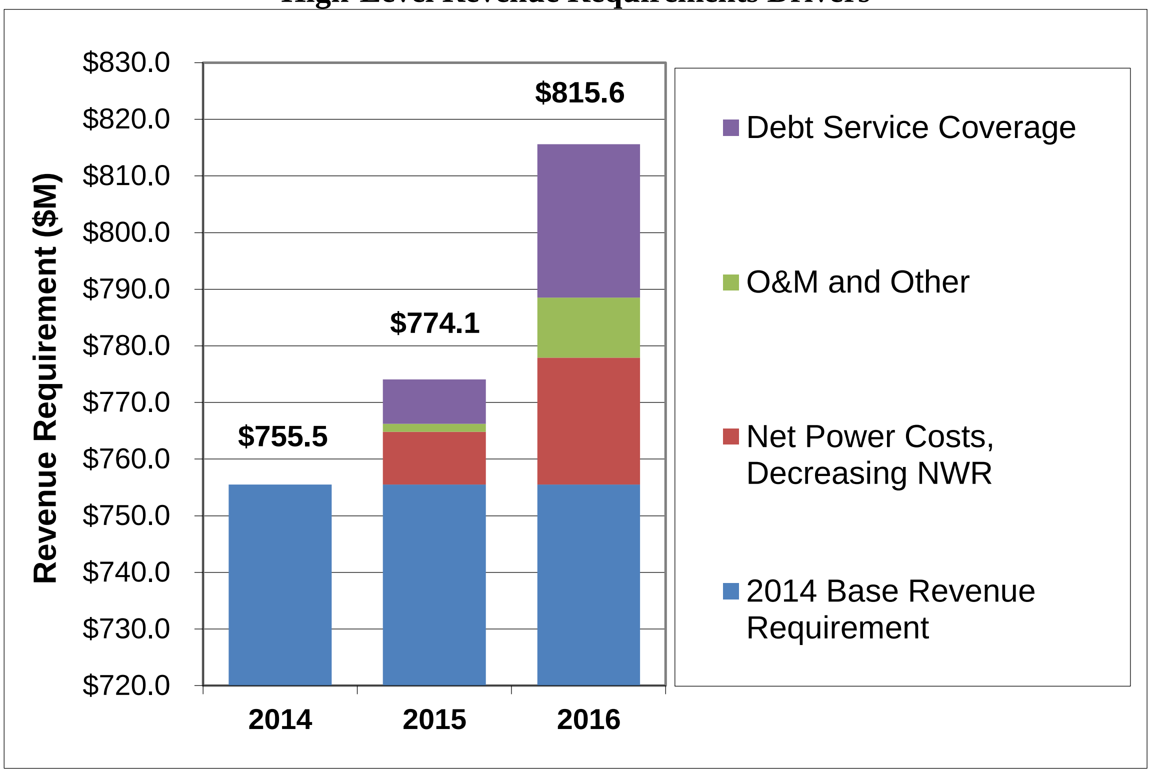


Table S2 provides a summary of the revenues and expenses assumed in this revenue requirement analysis (RRA).

Table S2
2015-2016 Revenue Requirement Calculation Summary

Chapter	RRA Category ($ Millions)	2014 Plan	2015 Forecast	2016 Forecast	Difference 2015-2014	Difference 2016-2015
1	Debt Service	$189.6	$194.0	$204.7	$4.4	$10.7
	Debt Service times 1.8	**$341.4**	**$349.2**	**$368.4**	**$7.8**	**$19.2**
2	**Operating Expenses**					
	Power Contracts	$274.4	$268.4	$274.8	($6.0)	$6.4
	Non-Power O&M	237.5	239.3	247.0	1.8	7.7
	Other Expenses	46.7	48.3	49.7	1.6	1.4
	Total	**$558.6**	**$556.0**	**$571.5**	**($2.6)**	**$15.5**
3	**Operating Revenues**					
	Net Wholesale Revenue	$85.0	$65.0	$60.0	($20.0)	($5.0)
	Power Revenues	23.0	27.7	26.0	4.7	(1.6)
	Other Sources	38.3	38.5	38.3	0.2	(0.1)
	Total	**$146.3**	**$131.1**	**$124.4**	**($15.1)**	**($6.8)**
4	**Revenue Requirements**					
	Adopted	$755.5	$774.1	$815.6	$18.6	$41.5
	Target	753.7	774.1	815.6	20.4	41.5
	Difference (Adopted - Target)*	$1.8	$0.0	$0.0	($1.8)	($0.0)

*In some years the target revenue requirement calculated with the budgeted revenues and expenses may not equal exactly the revenue requirement endorsed by the Strategic Plan. This is because the revenue requirement and the budget are completed in parallel, and typically the revenue requirement must be finalized before the budget is. Chapter 4 discusses the difference between the target and adopted revenue requirement in detail.

S.3 Changes in Average Rates

The 2014 Strategic Plan Update[1] calls for rate increases averaging **4.2%** in 2015 and **4.9%** in 2016. Table S3 summarizes retail revenue,[2] average rates and annual rate increases for 2015 and 2016. The first section shows the retail revenue generated from existing rates and the incremental retail revenue in 2015 and 2016 resulting from the revenue requirement increases described in this document. The second section provides the average rates for each year, which are calculated by dividing total retail revenue by the total sales to customers and multiplying by 100 (to get cents/kWh). The third section shows the average annual rate increase and a breakout showing how much of the increase is due to increases in the revenue requirement and how much is due to changes in the amount of expected retail customer sales.

[1] Adopted by the City Council June 30, 2014, by Resolution 31529.
[2] Retail revenue from energy charges, demand charges and base service charges from all customers.

Table S3
Changes in Average Rates

	2014 Plan	2015	2016
Retail Revenue ($M)			
Current Rates	$755.5	$742.7	$746.1
From 2015 Increase		31.4	31.6
From 2016 Increase			37.9
Retail Revenue Requirement	**$755.5**	**$774.1**	**$815.6**
Sales to Retail customers (GWh)	9,746	9,567	9,611
Avg Rates (cents / kWh)			
Current Rates	7.75	7.76	7.76
After 2015 Increase		8.09	8.09
After 2016 Increase			8.49
Annual Rate Increase		**4.2%**	**4.9%**
Change from Increased RR		2.3%	5.4%
Change from Expected Retail Sales		1.9%	-0.5%

The average annual rate increase is calculated compared to what the average system rate would be for that year without that year's rate increase (which may not be the same as the average rate for the previous year). This method accounts for any changes in projected retail sales. Note that an average rate is only a statistic and not actually a customer rate.

The 2015-16 Rate Study is a comprehensive one; therefore, the revenue requirement is only the first of three steps. First the revenue requirement is calculated, then the cost of service and cost allocation study divides the revenue requirement dollars among customer classes, and then finally rate design sets individual rates to collect this revenue. Therefore, the revenue requirement determines that the average rate increase across all customers is 4.2% and 4.9%, but each individual customer class will have a different rate increase that could be lower or higher than the system average.

Introduction

I.1 Introduction

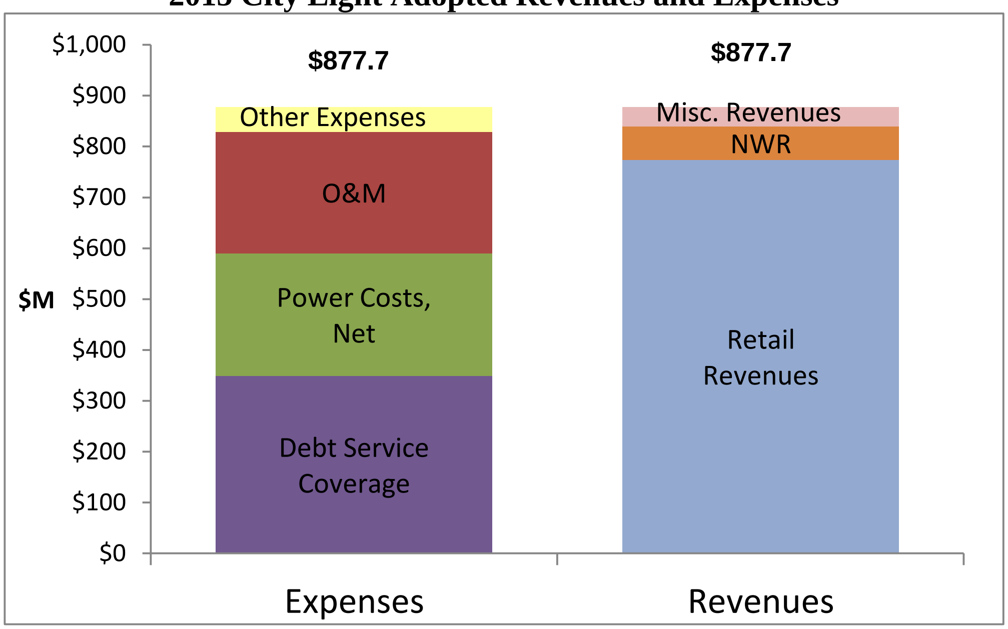
This report details the 2015 and 2016 revenue requirements developed for City Light's 2015-2016 Rate Study. The revenue requirement is the amount of revenue that City Light must collect from retail customers in a given year to cover operating costs and meet Council-mandated financial policies. Operating revenues, operating costs and capital expenditures (which drive debt service coverage) are determined by the budget, which is developed in conjunction with the revenue requirement. City Light's current rate setting financial policy specifies that rates should be set so that after all operating expenses the remaining net revenue will be equal to 1.8 times debt service.[3] The amount of net revenue available for debt service is also commonly referred to as debt service coverage.

The following equation helps demonstrate the basic derivation of the revenue requirements.

Revenue Requirements = Debt Service * 1.8 + Operating Expenses –Non-Rate Based Revenues

Figure 1 below shows how retail revenue is sized so that total revenues equal total expenses. It also illustrates the relative size of City Light's Revenues and Expenses.

Figure 1
2015 City Light Adopted Revenues and Expenses



The revenue and expenses used in the derivation of revenue requirements are consistent with the methodology for calculating debt service coverage for ratemaking. Note that rates use a slightly different definition of operating revenues and expenses than is used in the income statement, because the income statement includes non-cash transactions such as depreciation and mark-to-

[3] City Council Resolution 31187 passed in March 2010.

market valuation for certain energy purchases and sales. These types of transactions are not part of the debt service coverage calculation. City Light's 2013 Annual Financial Report provides information on specific types of adjustments made to the income statement categories.

I.2 RRA Objectives and Organization

The RRA's two main objectives are: (1) to summarize how the 2015 and 2016 revenue requirements are determined; and (2) to explain what has changed from the revenue requirements used to set the existing 2014 rates. To accomplish this, this report compares the forecast for the 2015 and 2016 revenues and expenses to the forecast that determined the 2014 rates, referred to as the 2014 Plan. The 2014 Plan is the 2014 Adopted Revenue Requirement adjusted for increased BPA power and wheeling costs and the associated retail rate pass-through that went into effect October 1, 2013. Note that 2014 actuals are not pertinent to this discussion; the RRA only compares the current proposal to the revenues and expenses used to determine the existing 2014 rates.

The RRA is organized into five chapters with appendices providing additional detail. Chapter 1 explains debt service and debt service coverage. Chapter 2 discusses operating expenses, while Chapter 3 discusses non-rate based revenue. The revenue requirement, which is calculated from the values in Chapters 1-3, is summarized in Chapter 4. Finally, Chapter 5 discusses indirect costs and proceeds, such as capital expenses and proceeds from bond issues. These impact the revenue requirements indirectly through their role in size and timing of future debt issues, which ultimately impact future revenue requirements.

Chapter 1: Debt Service and Debt Service Coverage

City Light finances a portion of its capital program by selling municipal revenue bonds. At the end of 2013 City Light held around $1.86 billion in long term debt obligations. The bonds are paid back over a term of 20 to 30 years through interest and principal payments, also called debt service. City Light's financial policies require it to set rates sufficient to cover debt service 1.8 times after all required operating expenses are paid. Therefore, changes in debt service have 1.8 times the impact on the revenue requirements that regular expenses have.

For the purpose of the financial forecast and the revenue requirements, federal interest subsidies are subtracted from interest payments instead of treating them as revenue.[4] Also, a 7.2% reduction in planned subsidy payments is assumed, to reflect the potential of reductions due to federal sequestration. Table 1.1 shows the debt service projections for the 2014 Plan compared with the forecast for 2015 and 2016 and the year to year changes. The debt service coverage requirement is increasing in both 2015 and 2016. The drivers of the increase are discussed below.

Table 1.1
Debt Service and Debt Service Coverage

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Debt Service , Gross	$195.0	$199.1	$209.7	$4.0	$10.7
Federal Subsidies	5.4	5.1	5.1	(0.3)	0.0
Debt Service , Net of Subsidies	189.6	194.0	204.7	4.4	10.7
Debt Service Coverage (1.8x)	**$341.4**	**$349.2**	**$368.4**	**$7.8**	**$19.2**

The debt issues are sized to meet City Light's forecasted cash requirements for approximately 12 months, resulting in annual debt issues each year. The details of the planned debt issues are shown in Table 1.2. The 2015 debt issue is expected to be the largest new money issue in over a decade, partly due to costs associated with the new Denny Way Substation. The below future debt issues are assumed to be fixed rate debt and do not anticipate any refinancing of existing debt.

Table 1.2
Planned Debt Issues

	Debt Issue Amount ($M)	Term (years)	Average Rate
2014 Planned Issue	$220.0	30	5.0%
2015 Planned Issue	292.4	30	5.0%
2016 Planned Issue	240.3	30	5.0%

Table 1.3 shows debt service by issue year. Debt service on existing debt is decreasing but the debt service on future debt is expected to increase at a faster rate, leading to a net increase in debt service. The Capital Improvement Plan (CIP) is the major driver of debt service; the CIP is discussed in detail in Appendix C.

[4] Federal interest subsidies are subsidies City Light receives on Build America Bonds (BABs), Conservation and Renewable Energy Bonds (CREBs) and Recovery Zone Economic Development Bonds (RZEDs). Traditional accounting treats the subsidies as revenues. With approval from City Light's financial advisors, the financial forecast does not count the subsidies as revenue but rather subtracts the subsidies from debt service and uses net debt service in the debt coverage calculations.

Table 1.3
Debt Service by Bond Series[5]

$ Millions	2014 Plan	2015	2016
Debt Service by Bond Series			
2002-2004 Unrefunded Bonds	$23.6	$18.2	$14.8
2008 Bonds	26.0	26.1	24.1
2010 Bonds	78.3	77.7	78.4
2011 Bonds	26.5	26.9	26.5
2012 Bonds	24.5	26.7	25.4
2013 Bonds	16.3	11.6	11.6
Subtotal	**$195.1**	**$187.2**	**$180.8**
Future Debt			
2014 Bonds	-	$11.8	$11.8
2015 Bonds	-		17.1
2016 Bonds	-	-	-
Subtotal	-	**$11.8**	**$28.9**
Federal Subsidies	$5.4	$5.1	$5.1
Total Debt Service Net of Subsidies	**$189.6**	**$194.0**	**$204.7**

Debt service on the 2014 debt issue assumes $2.5M in interest savings, reflecting debt management efficiencies assumed in the 2014 Strategic Plan Update, based on potential improved liquidity management and/or the possible issuance of variable rate debt.

[5] The debt service payments for many of these bond series reflect refinancing, so the debt service payments on these bonds are not just for the debt issued to cover capital expenses in those years.

Chapter 2: Operating Expenses

2.1 Introduction

Operating expenses are grouped into power contracts expenses, non-power O&M and other expenses. Table 2.1 shows the operating expenses and the annual changes.

Table 2.1
Operating Expenses

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Power Contracts	$274.4	$268.4	$274.8	($6.0)	$6.4
Non-Power O&M	237.5	239.3	247.0	1.8	7.7
Other Expenses	46.7	48.3	49.7	1.6	1.4
Total	**$558.6**	**$556.0**	**$571.5**	**($2.6)**	**$15.5**

2.2 Power Contract Expenses

Power contract expenses include the costs City Light pays to third parties for the acquisition and transmission of energy. Table 2.2 summarizes planned power contract expenditures for 2015 and 2016 and compares them with the prior year. A more detailed description of power contracts is located in Appendix A.

Table 2.2
Power Contract Expenses

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Long Term Purchased Power					
BPA	$165.7	$165.0	$169.4	($0.7)	$4.5
Priest Rapids	3.3	3.1	3.2	(0.2)	0.1
Grand Coulee	5.8	5.9	6.1	0.1	0.1
High Ross	13.1	13.1	13.1	0.0	0.0
Lucky Peak	7.0	7.1	7.3	0.1	0.2
Stateline Wind Project	26.9	27.0	27.2	0.1	0.1
Small Renewables	10.4	10.6	10.9	0.2	0.2
Subtotal	**$232.3**	**$231.9**	**$237.2**	**($0.3)**	**$5.2**
Wheeling					
BPA Firm Wheeling	$40.9	$37.3	$38.4	($3.6)	$1.2
South Fork Tolt	0.4	0.4	0.4	(0.0)	(0.0)
Grand Coulee (Local)	0.2	0.2	0.2	0.0	0.0
Other, Net	0.6	(1.4)	(1.4)	(2.0)	0.0
Subtotal	**$42.1**	**$36.5**	**$37.6**	**($5.6)**	**$1.2**
Total Power Contracts	**$274.4**	**$268.4**	**$274.8**	**($6.0)**	**$6.4**

Long Term Purchased Power Expenses
The forecast of power expenses is based on the power contracts budget. In some cases the forecast uses values that are different from the budget; these differences are discussed in Appendix B. In total, Long Term Purchased Power expenditures in 2015 are forecasted to stay close to planned 2014 levels but increase in 2016 by $5.2 million, primarily due to higher BPA expenses. BPA Power Costs were set at levels consistent with the Strategic Plan (see *BPA Expenses*).

Wheeling Expenses
Wheeling Expenses consist of payments for transmission services under long term contracts. As shown in Table 2.2, BPA is City Light's primary provider of wheeling services (see *BPA Expenses*). The "Other, Net" wheeling category is negative because it includes $2.0 million in power-related savings that are expected to come from lower expenditures in power and wheeling costs or increased power related revenues.

BPA Expenses
BPA Power and Wheeling Expenses in the 2014 Strategic Plan Update were set at the levels established in the previous (2012) Strategic Plan, which assumed CPI inflation of approximately 2% per year. In the 2016 federal fiscal year beginning October 1, 2015, BPA rates may increase more than the amount assumed in the Strategic Plan update. When the final decision is published in late summer of 2015, City Light will evaluate the effect of new BPA rates in relation to City Light's expense assumptions. Any costs not already included in base rates will be recovered through the automatic BPA pass-through mechanism, pursuant to SMC 21.49.081.

2.3 Non-Power Operating and Maintenance Expenses

Non-power operating and maintenance expenses are the costs associated with day-to-day operations. This is a large and diverse category of costs that include functions such power production, distribution and transmission system operation and maintenance, customer services such as billing and meter reading, and administrative support.

Non-Power O&M Budget
The basis for the non-power O&M in the financial forecast is the 2015-2016 Proposed Budget, adjusted to remove costs that do not impact City Light's debt service coverage. (This adjustment is discussed in more detail below.) Table 2.3 shows the non-power O&M by budget control level (BCL).[6]

[6] For more detail see City Light's 2015-2016 Proposed Budget. City Council adopted rates on October 6, 2014, before the adoption of the 2015-2016 Budget.

Table 2.3
Proposed 2015 and 2016 O&M Budget

$ Millions	2014 Adopted	2015 Proposed	2016 Proposed
Non Power O&M in Budget (includes Deferred O&M)			
Office of Superintendent	$3.2	$3.5	$3.5
Power Supply	50.8	51.0	51.7
Conservation Resources and Environmental Affairs	61.4	61.9	63.0
Distribution Services	74.1	77.5	79.5
Customer Services	28.0	29.8	30.2
Human Resources	9.0	9.2	9.3
Financial Services	36.7	40.1	42.3
General Expenses	88.1	90.3	94.3
Compliance and Security	3.4	3.6	3.7
Total	**$354.8**	**$366.8**	**$377.5**

The annual increases to the Proposed Budget are explained by either:

1. Budget Issue Papers (BIPs): New initiatives and/or policy related changes in funding levels for existing programs.
2. Technical BIPs: Changes that are not policy or new initiative related, such as transfers between BCLs, accounting changes, or City cost allocations.
3. Inflation: Increases for labor wages, labor benefits, supplies and all other operating costs.

Table 2.4 breaks down the changes to the O&M budget by two categories, Inflation and Technical BIPs and BIPs. In aggregate, O&M increases average around 3.4% for 2015 and 2.9% for 2016, though each budget cost category was assigned a specific inflation factor. Consistent with the 2012 Strategic Plan, the 2014 Plan included $6.0 million of O&M efficiency savings (relative to the 2012 Adopted Budget). The 2015 and 2016 savings called for in the 2014 Strategic Plan Update add an additional $2.0 million, resulting in an annual O&M savings target of $8.0 million annually.

The majority of O&M initiatives identified in the 2012 Strategic Plan started in 2013 and 2014 and therefore these expenses are embedded in the 2014 Adopted Budget. 2015 includes $2.0 million of spending related to new initiatives, and 2016 adds an additional $0.1 million. Appendix B provides a more detailed breakdown of the BIPs for 2015 and 2016.

Table 2.4
Summary of Budget Changes

$ Millions	2015	2016
Previous Year (2014) Adopted	$354.8	$366.8
Inflation and Technical BIPs	9.9	10.7
BIPs	2.0	0.1
Proposed O&M Budget	**$366.8**	**$377.5**

Adjustments from Budget to Financial Forecast
To correspond with the debt service coverage computation, the expenses taken from the budget are adjusted to include only costs that will be applied to the debt service coverage calculation. This includes adjustments such as excluding deferred O&M and all projected capitalized and deferred labor loadings, as well as including any items that are in the purchased power budget but are

included in non-power O&M in the financial forecast. In addition, a $10 million under-expenditure assumption was added, which equals roughly 3% of total O&M and is consistent with O&M budget under-expenditures observed over the past few years. Table 2.5 provides a summary of the budget-to-forecast adjustments and the resulting non-power O&M expenses used in the financial forecast.

Table 2.5
Summary of Budget to Forecast Adjustments

$ Millions	**2014 Plan**	**2015**	**2016**	**Difference 2015-2014**	**Difference 2016-2015**
Total O&M Budget	**$354.8**	**$366.8**	**$377.5**	**$12.0**	**$10.7**
Adjustments:					
Capital Loadings	(78.3)	(76.8)	(78.4)	1.6	(1.6)
Deferred O&M	(47.4)	(47.5)	(47.4)	(0.1)	0.1
Under-Expenditure Assumption		(10.0)	(10.0)	(10.0)	-
O&M Forecast Costs in Power Budget	4.6	6.5	7.5	2.0	0.9
Total Non-Power O&M for Financial Forecast	**$233.7**	**$239.1**	**$249.1**	**$5.4**	**$10.1**
Total Non-Power O&M Included in Financial Forecast	**$237.5**	**$239.3**	**$247.0**	**$1.8**	**$7.7**
Difference	(3.9)	(0.2)	2.1	3.6	2.4

O&M in the Financial Forecast is based on the 2014 Strategic Plan. However, the Proposed Budget that was developed based on the Strategic Plan included some adjustments and updated assumptions, primarily to inflation. The resulting differences are shown in the last row of Table 2.5. The 2014 difference arises from the difference between the 2014 Adopted and Proposed Budget.

O&M for 2015 is expected to only go up by $1.8 million compared to the 2014 Plan. The primary reason for the lower annual change relative to the O&M budget is the $10 million under-expenditure assumption, which was not a part of the 2014 Plan. In 2016 O&M is expected to increase $7.7 million over 2015 levels, largely driven by inflation. The $1.8 million and $7.7 million annual increases in the non-power O&M forecast account for roughly 9% and 19% of the total increase in 2015 and 2016 revenue requirements, respectively.

2.4 Other Expenses

Other expenditures include uncollectable accounts, state taxes, other (non-City) taxes and franchise payments.[7] Table 2.6 shows the 2014 Plan compared to the 2015 and 2016 forecasts. Following the table is a short description of each category.

[7] Taxes paid to the City of Seattle are junior to debt service and therefore are not included in the calculation of debt service coverage.

Table 2.6
Other Expenses

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Other Expenses					
Uncollectable Accounts	$6.8	$7.0	$7.4	$0.2	$0.4
State Taxes	29.6	31.0	32.5	1.4	1.5
Other (Non-City) Taxes	4.3	4.4	3.7	0.1	(0.7)
Franchise Payments	5.9	5.9	6.2	0.0	0.3
Total	**$46.7**	**$48.3**	**$49.7**	**$1.6**	**$1.4**

Uncollectable Accounts

Every year, a portion of past-due accounts receivable are never received, despite collection efforts, and must be written off as uncollectable. Uncollectable accounts include both retail customers and wholesale counterparties. Uncollectable revenue is projected to remain at around 0.9% of revenue from energy sales to retail customers.

State Taxes

City Light pays a state utility tax on retail revenue and on certain other sources of outside revenue including Contributions in Aid of Construction (CIAC). It is assumed that 6% of revenues are not taxable and deducted from the tax base. The remaining revenue is taxed at the State rate of 3.8734%. These taxes are projected to be slightly higher in 2015 and 2016 because of increases in retail revenue. In addition to the state utility tax, City Light pays a state business tax, which amounts to around $0.1 million per year.

Other (Non-City) Taxes

City Light makes payments to some states, counties and school districts where its production facilities are located. The only notable change in these expenses comes from a small increase in quarterly impact payments to Pend Oreille County in 2015 followed by a decrease in these payments in 2016, as specified in a contract signed in 2010.

Payments to Franchise Cities

City Light 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 are calculated as a percentage of the projected retail revenue billed to customers in these suburban cities. They are projected to increase in 2016 with rates, but are flat for 2015 due to changes in franchise agreement terms and energy consumption characteristics.

Chapter 3: Non-Rate Based Revenue

3.1 Introduction

In addition to revenue from retail sales, City Light receives cash from other non-rate sources such as wholesale power sales, long-term power contracts, transmission and power-related services, investment income and other fees and charges. Table 3.1 shows forecasted non-rate based revenues for 2015 and 2016 and compares them with the 2014 Plan.

Table 3.1
Non-Rate Based Revenues

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Non-Rate Based Revenue					
Net Wholesale Revenue	$85.0	$65.0	$60.0	($20.0)	($5.0)
Power Revenues	23.0	27.7	26.0	4.7	(1.6)
Other Sources	38.3	38.5	38.3	0.2	(0.1)
Total	**$146.3**	**$131.1**	**$124.4**	**($15.1)**	**($6.8)**

3.2 Net Wholesale Revenue

Revenue from wholesale power sales net of purchases, also commonly referred to as net wholesale revenue (NWR), is the cash derived from the sale of power that is surplus to system load and other obligations. Table 3.2 lists the assumptions for NWR, which is also the baseline value for the Rate Stabilization Account (RSA).[8]

Table 3.2
Planning Value for Net Wholesale Revenue

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Net Wholesale Revenue	$85.0	$65.0	$60.0	($20.0)	($5.0)

The 2012 Strategic Plan included an initiative to gradually reduce planned NWR each year through 2018, with values of $85 million and $75 million for 2015 and 2016 respectively. The 2014 Strategic Plan Update includes much more conservative NWR targets which greatly reduce the probability of an RSA surcharge.

3.3 Power Revenues

Power revenues include revenue from long term power contracts, and revenue (net of purchases) from various power marketing activities. Table 3.3 details these revenues, which are discussed in more detail below.

[8] Ordinance 123260, adopted March 2010, Council Bill 118193 of September 2014, and Resolution 31529, adopted June 2014.

Table 3.3
Summary of Power Revenues

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Revenue from Power Contracts					
Article 49 Sales to PO County	$1.8	$1.9	$1.9	$0.0	$0.0
Sales from Priest Rapids	4.8	5.8	5.8	1.0	0.0
BPA Credit for South Fork Tolt	3.2	3.2	3.1	0.0	(0.1)
BPA Residential Exchange Credit	5.3	5.7	5.7	0.4	(0.0)
Subtotal	**$15.2**	**$16.6**	**$16.5**	**$1.4**	**($0.1)**
Power Marketing Revenue, Net					
Transmission Revenue	$4.4	$6.0	$4.4	$1.6	($1.6)
Sale of Lucky Peak Output	2.1	2.1	2.1	0.0	0.0
REC Sales	1.5	0.0	0.0	(1.5)	0.0
Other Services, Net	(0.2)	3.0	3.0	3.2	0.0
Subtotal	**$7.8**	**$11.1**	**$9.6**	**$3.3**	**($1.5)**
Total	**$23.0**	**$27.7**	**$26.0**	**$4.7**	**($1.6)**

Power Contracts
This revenue category includes contractual payments that City Light receives from third parties. Similar to the power contracts expenses, the forecast is based on the biennial power contracts budget. Power contracts revenue is projected to be $1.4 million higher in 2015 than in the 2014 Plan. The primary driver is a slight increase in Priest Rapids Reasonable Portion revenues, attributable to higher projected proceeds from the Grant County PUD annual power auction, of which City Light receives a portion. Revenue from the BPA Residential Exchange credit is also projected to be slightly higher than in 2014.

Power Marketing, Net
Power Marketing revenues include sales of surplus transmission capacity, premiums associated with the sale of Lucky Peak output, Renewable Energy Credits (RECs), as well as purchases and sales of other ancillary services (e.g., reserve energy and capacity, parking and shaping) that extract value from City Light's generation assets. The forecast projects 2015 net revenues to be $3.3 million higher than the 2014 Plan. The increase is driven by higher expectations of sales for transmission services and higher reserve capacity sales. These increases are slightly offset by a reduction in surplus REC sales, due to the Washington State I-937 renewable portfolio requirement increasing. The decrease in 2016 is due to lower transmission revenue; power management plans to reduce sales of transmission and instead directly market energy to California. The higher energy prices in these markets should translate to an increase in net wholesale revenue, but this not reflected in the forecast since NWR is a value set by policy.

3.4 Other Revenue Sources

This category includes cash from a variety of sources such as late payment fees, property rentals, sales of property, investment income, operating fees and grants. Other revenues are generally projected using historical trends and inflation. Table 3.4 shows the forecast of Other Revenue Sources, which is projected to remain relatively constant in 2015 and 2016. However, in 2015 there are some notable differences in the individual categories, which are discussed below.

2015 Compared to 2014 Plan

- Higher Other Revenue, based on history and inflation
- Lower Investment Income (interest earned on City Light's portion of the City's cash pool), due to lower interest rates; average of 1.5% for 2015 and 2016.
- Higher operating fees and grants; assumes $1 million grant in 2015 related to Duwamish River cleanup.
- Reduced RSA transfers (offset to revenue): lower interest rates earned on RSA balance (transferred to RSA) and a small tax adjustment for RSA surcharge.[9]
- Lower Green Power Programs: Revised downward to reflect a more conservative estimate of customer participation.

Table 3.4
Other Revenue Sources

$ Millions	2014 Plan	2015	2016	Difference 2015-2014	Difference 2016-2015
Other Sources of Revenue					
Other Revenue	$23.3	$24.7	$25.2	$1.4	$0.5
Investment Income	9.5	7.4	8.4	(2.1)	1.0
Sale of Property	1.1	1.0	1.0	(0.1)	0.0
Suburban Undergrounding	1.3	0.9	1.1	(0.4)	0.2
Operating Fees and Grants	0.0	1.0	0.0	1.0	(1.0)
RSA Transfers	(2.0)	(0.2)	(1.1)	1.8	(0.9)
Distribution Capacity Charge	0.2	0.2	0.2	0.0	0.0
Green Power Programs	2.9	1.1	1.1	(1.8)	0.0
Power Factor Charges	2.6	3.0	3.0	0.3	0.1
less					
Credits for Transformation	0.4	0.4	0.4	0.0	0.0
Emergency Low Income Assistance	0.3	0.3	0.3	0.0	0.0
Total	**$38.3**	**$38.5**	**$38.3**	**$0.2**	**($0.1)**

Other Revenue Sources include $1.0 million annually for sales of miscellaneous property, but do not include revenues from the anticipated sale of the Roy Street property, which is expected to yield $18 million in revenue in 2015. Per the 2014 Strategic Plan, the Roy Street Sale is treated like a capital program contribution, which only indirectly impacts the revenue requirement by reducing the amount of debt issued.

[9] The revenue requirement forecast assumed poor hydro conditions for 2014 and a resulting RSA surcharge in 2015. Since the forecast was completed, hydro conditions improved dramatically, eliminating the expected 2015 surcharge. Any surcharge revenue nets with RSA transfers and would not impact the revenue requirement. However, there is a small tax impact from the additional surcharge revenue.

Chapter 4: Retail Revenue from Base Rates

Revenue Requirement
The revenue requirement is comprised of retail revenue collected from all customers through energy charges, demand charges and base service charges. That is, it is the total amount of revenue City Light needs to collect from all customers in a given year. Revenue requirements are shown net of any rate discounts given to Utility Discount Program customers. The revenue requirements are $774.1 million in 2015 and $815.6 million in 2016, and result in annual average rate increases of 4.2% and 4.9%, respectively.

City Light's rate setting guideline[10] calls for retail rates be set so that after all operating expenses are paid, there will be enough net revenue remaining to cover the annual debt service by 1.8 times. Table 4.1 shows that the adopted revenue requirements meet this financial policy given the debt service, operating expenses and non-retail operating revenues discussed in Chapters 1 through 3.

Table 4.1
Debt Service Coverage with Adopted Retail Revenue Requirements

$ Millions	**2014 Plan**	**2015**	**2016**	**Difference 2015-2014**	**Difference 2016-2015**
Adopted Retail Revenue	$755.5	$774.1	$815.6	$18.6	$41.5
Operating Expenses	558.6	556.0	571.5	(2.6)	15.5
Non-Rate based Revenue	146.3	131.1	124.4	(15.1)	(6.8)
Amount Available for Coverage	**$343.2**	**$349.2**	**$368.4**	**$6.0**	**$19.2**
Debt Service	$189.6	$194.0	$204.7	$4.4	$10.7
Debt Service Coverage Ratio	1.81	1.80	1.80	(0.01)	0.00

Table 4.2
Adopted-Target Differences

$ Millions	**2014 Plan**	**2015**	**2016**	**Difference 2015-2014**	**Difference 2016-2015**
Adopted Retail Revenue	$755.5	$774.1	$815.6	$18.6	$41.5
Target Revenue Requirement	753.7	774.1	815.6	20.4	41.5
Difference	**$1.8**	**$0.0**	**$0.0**	**($1.8)**	**$0.0**

The budget and rates are developed in parallel based on the Strategic Plan, and sometimes small adjustments in the budget occur too late to be incorporated into the rates. To make the relationship between the budget and rates as transparent as possible, budget data may be incorporated directly into the forecast, and this results in a forecasted debt service coverage that may differ slightly from the prescribed 1.80 times. Informally, the allowable margin of error is defined such that the 1.8 times coverage condition must be met to two significant digits.

The Target Revenue Requirement is revenue needed to provide exactly 1.80 debt service coverage. The Adopted Revenue Requirement is the actual planned retail revenue. As shown in Tables 4.1 and 4.2, the adopted retail revenue is $1.8 million higher than the target, which yielded planned debt service coverage for 2014 slightly higher than 1.80 times. The 2015 and 2016 retail revenues yield coverage of exactly 1.8 times.

[10] Established by Resolution 31187.

Average Rates and Annual Rate Increases

Table 4.3 summarizes retail revenue,[11] average rates and annual rate increases for 2015 and 2016. The first section shows the retail revenue generated from existing rates and the nominal increase in retail revenue in 2015 and 2016 resulting from the adopted revenue requirement increases. The second section provides the average rates for each year, which are calculated by dividing total retail revenue by the total sales to customers and multiplying by 100 (to get cents per kWh). The third section details the average annual rate increase and shows how much of the change is attributable to revenue requirement and how much is due to changes in retail sales.

Table 4.3
Revenue Requirements and Average Retail Rates

	2014 Plan	2015	2016
Retail Revenue ($M)			
Current Rates	$755.5	$742.7	$746.1
From 2015 Increase		31.4	31.6
From 2016 Increase			37.9
Retail Revenue Requirement	**$755.5**	**$774.1**	**$815.6**
Sales to Retail Customers (GWh)	**9,746**	**9,567**	**9,611**
Avg Rates (cents / kWh)			
Current Rates	7.75	7.76	7.76
After 2015 Increase		8.09	8.09
After 2016 Increase			8.49
Annual Rate Increase		**4.2%**	**4.9%**
Change from Increased RR		2.3%	5.4%
Change from Expected Retail Sales		1.9%	-0.5%

The forecast of retail energy sales, or load forecast, plays a non-trivial role in the size of the annual rate increase. Given a revenue requirement, a higher sales base will produce a lower average rate.

The load forecast for 2015 is 1.8% lower than the load from the 2014 Plan[12], primarily due to slow economic growth and lower assumed load from the Alaskan Way tunnel boring machine. The reduction in expected 2015 retail sales relative to the 2014 Plan is responsible for 1.9% or almost half of the total 4.2% increase in the average rate. In contrast, load is expected to increase 0.5% from 2015 to 2016, reducing the average rate increase.

[11] Retail revenue from energy charges, demand charges and base service charges from all customers.

[12] The 2014 Plan used residential sales from the adopted 2012 load forecast, while the 2015 and 2016 rates use the adopted 2013 load forecast. The 2014 load forecast was not released until late summer 2014, too late to incorporate into this rate review.

Chapter 5: Indirect Costs and Proceeds

Indirect expenses and proceeds include capitalized expenses, City taxes and cash adjustments. These do not directly impact the revenue requirement in the year in which they occur, but influence the amount of long-term debt issued in each year, which drives future revenue requirements through debt service coverage. Table 5.1 details indirect costs for 2015 and 2016. Note that debt service and the amount available for debt service are discussed in Chapters 1 and 4, respectively.

Table 5.1
Indirect Costs and Proceeds ($M)

$ Millions	**2015**	**2016**
Cash From Operations		
Amount Available for Debt Service	$349.2	$368.4
less		
Debt Service	194.0	204.7
City Taxes	49.6	51.9
Roy Street Property Sale	(18.0)	0.0
Cash Adjustments	14.3	14.7
Total	**$109.4**	**$97.1**
Sources of Capital Funding		
Cash from Operations	$109.4	$97.1
Cash from (to) Cash Balances	1.2	76.2
Bond Proceeds	274.6	227.9
Capital Contributions	32.3	39.0
Total	**$417.5**	**$440.2**
Capital Expenses		
CIP	$363.4	$385.4
Deferred O&M	54.1	54.8
Total	**$417.5**	**$440.2**

5.1 City Taxes

Unlike State taxes, taxes paid to the City of Seattle are junior to debt service and therefore are not included in the calculation of debt service coverage. Thus, City taxes are an indirect expense. City Light pays the City of Seattle an occupation tax equal to 6.0% of retail revenue and some other sources of outside revenue including interest earnings and contributions in aid of construction (CIAC). In addition to the occupation tax, City Light pays the City of Seattle a small business tax. City taxes increase proportionally with retail revenue.

5.2 Roy Street Property Sale

As mentioned in section 3.4, City Light plans on selling a property on Roy Street in 2015 for $18 million. This large sale will not directly impact debt service coverage but the proceeds will reduce the amount of debt issued in 2015, reducing future debt service.

5.3 Cash Adjustments

There are a number of operating costs and revenues implicit in the amount available for debt service that are accounted for on an accrual basis but the actual cash transactions are lagged. Cash adjustments are made for costs/revenues that are accrued in the previous year but which will be paid/received in the current year, and for costs/revenues that have been accrued in the current year but which will be paid/received in the following year. For example, the retail revenue discussed in Chapter 4 is accrued revenue based on the energy that will be delivered to customers in the current year. City Light will still have to read the meters, bill the customers and collect the payments. Thus, there will be a lag from the time the retail energy is delivered and the revenue is accrued to when the payments are received. Cash adjustments are made to estimate the amount of operating cash flow that will be available for the capital program. These cash flows are referred to as cash from operations, which are treated as a source of capital funds.

In addition to cash lags, certain elective cash transfers also restrict operating funds, making them ineligible to put towards the capital program. The forecast assumes annual transfers of $10 million in operating cash to the restricted bond reserve, in addition to regular bond reserve deposits needed to meet reserve requirements. This is a policy decision intended to slowly build up funds to replace the existing $77.1 million surety bond. The surety bond does not expire until 2029, but the credit rating of its provider (FSA/Assured) has declined, so this is a conservative measure to ensure the funds will be available should they be needed.

5.4 Capital Expenditures and Funding Sources

Overview
City Light 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.

Table 5.2 presents a high level overview of all capital expenditures and funding sources. See Appendix C for more details about the capital program and its funding sources.

Table 5.2
Total Capital Expenditures and Funding Sources

$ Millions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
CIP	$363.4	$385.4	$271.1	$235.9	$318.6	$343.9	$1,918.5
Conservation	39.8	40.9	42.1	43.3	44.6	45.9	256.7
High Ross Payment Amortization	9.1	9.1	9.1	9.1	9.1	9.1	54.6
Relicensing, Mitigation and Other Costs	5.2	4.7	7.1	7.3	7.4	7.6	39.4
Total Funds Required	**$417.5**	**$440.2**	**$329.4**	**$295.7**	**$379.8**	**$406.5**	**$2,269.1**
Funds Available							
Cash from Operations	$109.4	$97.1	$103.8	$110.6	$112.7	$117.0	$650.6
Cash from Contributions	32.3	39.0	28.8	27.6	23.9	24.2	175.9
Cash from Bond Sale	274.6	227.9	197.0	192.7	265.4	206.4	1,363.8
Cash from Working Capital Account	1.2	76.2	(0.1)	(35.2)	(22.3)	58.9	78.7
Total Funds Available	**$417.5**	**$440.2**	**$329.4**	**$295.7**	**$379.8**	**$406.5**	**$2,269.1**

Summary of the CIP and other deferred costs
The six-year capital plan expenditures and deferred O&M include loadings for benefits and transportation, as well as administration and general cost allocations based on the number of labor hours estimated for each project. The financial forecast is a cash view and includes cash flow adjustments from the budgeted numbers. Based on historical trends, the forecast assumes a10% under-expenditure in CIP.

Total CIP expenses in the RRA are from the 2014 Strategic Plan Update and differ slightly from the 2015 Proposed CIP Plan due to timing adjustments on a number of projects that were identified after the 2014 Strategic Plan Update was completed. However, these adjustments mostly net out over the six years.

CIP expenditures are projected to total $1.9 billion over the six years of the Proposed CIP plan. The forecast classifies CIP expenditures according to functional categories: power supply, distribution, transmission, central utility and external projects. Figure 5.1 shows the annual amounts of planned CIP in the financial forecast by functional category. Figure 5.2 shows a pie chart of these expenditures for the period 2015-2020. Distribution is the largest category, representing 54.9% of the total CIP expenditures. The second largest is power supply expenditures.

Figure 5.1
2015 CIP

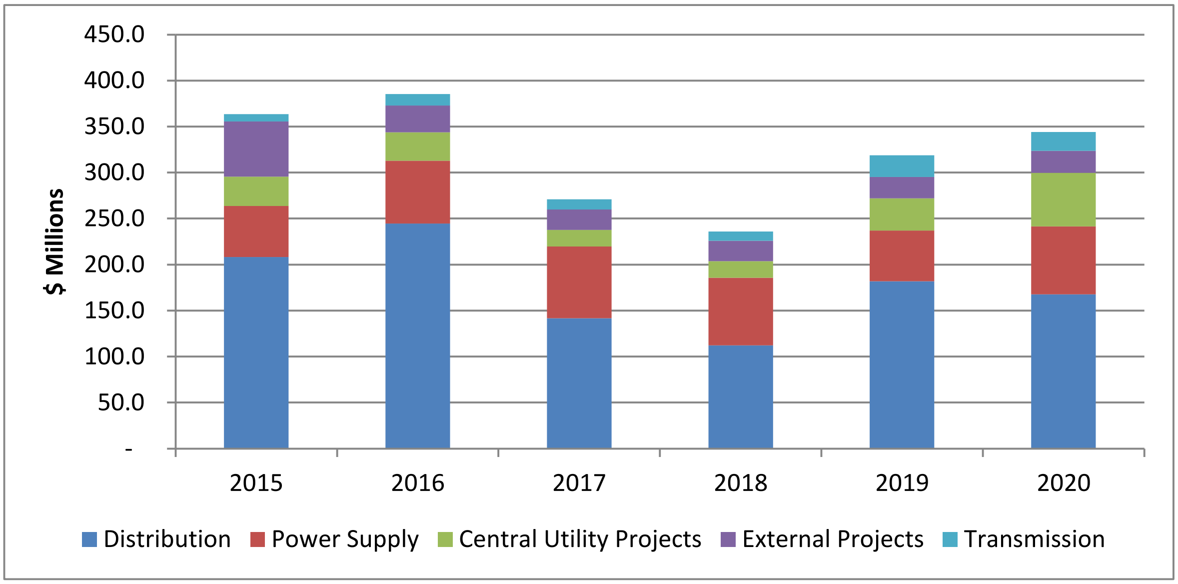
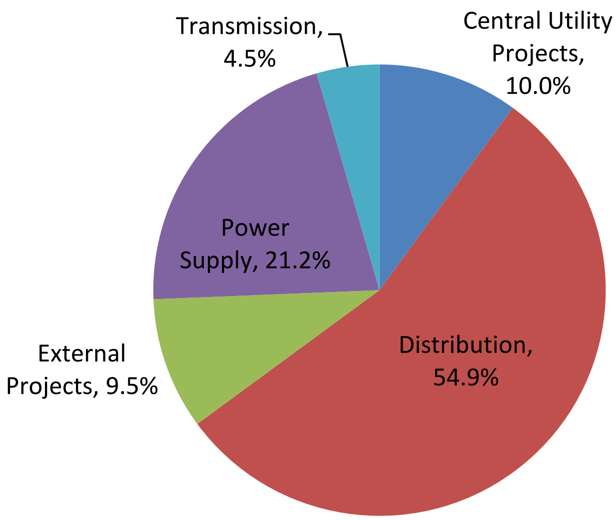


Figure 5.2
CIP 2015 – 2020 by Category



In addition to CIP expenditures, City Light also defers certain costs which are displayed in Table 5.2. Conservation installations are considered to be long-term energy resource investments and have been treated as deferred since 1984 per Council Resolution 27372. Costs associated with the High Ross Agreement, environmental cleanup, and some relicensing of City Light dams are also treated as deferred. While these costs do not produce assets, they still relate to activities that have impacts extending beyond the year these payments are made. Environmental cleanup costs of Superfund and other sites have been amortized since 2013.

Effect on Revenue Requirements

Capital expenditures, deferred conservation and other deferred costs do not affect current period revenue requirements but they do 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. Therefore, these expenses have a significant impact on rates in future years.

Funding sources

Capital requirements of $2.3 billion from 2015 through 2020 (including $1.9 billion of CIP and $350.7 million of certain capitalized other costs) are expected to be financed through a combination of cash from operations (net revenues), contributions in aid of construction, reimbursement of costs for transportation-related projects, external conservation funding, and the proceeds of future bonds.

Appendix A: Power Contracts Details

Bonneville Power Administration (BPA)
BPA markets power from the Federal Columbia River Power System (the "Federal System"), comprised of 31 federal hydroelectric projects, several non-federally-owned hydroelectric and thermal projects in the Pacific Northwest region, and various contractual rights. The federal hydroelectric projects are built and operated by the United States Bureau of Reclamation (the "Bureau") and the United States Army Corps of Engineers (the "Corps"), and are located primarily in the Columbia River basin. The Federal System currently produces more than 33% of the electric power consumed in the region. BPA's transmission system includes over 15,000 circuit miles of transmission lines and provides about 75% of the high-voltage bulk transmission capacity in the Pacific Northwest. Its service area covers over 300,000 square miles and has a population of about 12 million. BPA sells electric power at cost-based wholesale rates to more than 125 utility, industrial, and governmental customers in the Pacific Northwest. BPA is required by law to give preference to consumer- or publicly-owned utilities and to customers in the Pacific Northwest region in its wholesale power sales.

City Light has a 17-year Power Sales Agreement with BPA beginning October 1, 2011, according to which the power is delivered in two products: a shaped block product ("Block"), which is delivered in set amounts at set times, and a slice of the system product ("Slice"), which is a percentage of the Federal System, delivered as it is generated. Currently, City Light receives 268 aMW of the Block power annually, reduced by the amount of conserved energy savings purchased by BPA from City Light. The Slice product provides City Light with a fixed 3.62762% of the actual output of the Federal System for federal fiscal year ("FFY") 2014 and obligates City Light to pay the same percentage of the actual costs of the Federal System. Under critical water conditions, the Slice purchase amounts to 263 aMW over the year. Power available under the Slice product varies with water conditions, federal generating capabilities, and fish and wildlife restoration requirements.

BPA is required by federal law to recover all of its costs through the rates it charges its customers. BPA conducts a rate case every two years, but the rates are subject to a cost recovery adjustment clause that allows rates to increase during a two-year rate period if certain events occur. In July 2013, BPA adopted new power and transmission rates for FFY (Federal Fiscal year, which runs October to September) 2014-2015.

Priest Rapids
Under two agreements effective November 2009 through 2052, City Light purchases a portion of the output of the Priest Rapids Project, which is owned and operated by Public Utility District No. 2 of Grant County ("Grant PUD"). The Priest Rapids Project is comprised of two Columbia River dams, Priest Rapids and Wanapum, and has a total installed capacity of 1,893 MW.

Under the Reasonable Portion contract City Light's share of projected costs depends on the size of Grant PUD's withdrawal from the power auction proceeds. The maximum percentage of City Light's Reasonable Portion contract is 6.14%. City Light also receives a portion of the revenues from an auction of 30% of the project power.

The Conversion Product provides City Light a fixed slice of firm and non-firm project output through the entire project license term. The percentage City Light receives is equal to 0.27 percent or approximately 3 aMW from the Priest Rapids Project and City Light pays an equal percentage of the Total Priest Rapids Project costs.

Under the Meaningful Priority contract, City Light can also elect to purchase an additional share of Priest Rapids, at the same price as the winning auction bidder. For 2015 and 2016, the forecast assumes that City Light will not elect to purchase this power.

Grand Coulee

City Light, in conjunction with Tacoma Power, has power purchase agreements with three Columbia Basin irrigation districts for 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. The plants generate power only in the summer and thus have no winter peak capability. Plant output and costs are shared equally between City Light and Tacoma Power.

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.

Lucky Peak

The Lucky Peak Hydroelectric Power Plant was developed by three Idaho irrigation districts and one Oregon irrigation district (the "Districts") and is located on the Boise River, approximately ten miles southeast of Boise, Idaho, at the Lucky Peak Dam and Reservoir. Its FERC license expires in 2030. The nameplate capacity is 101 MW, but the plant operates only during the irrigation season, so it provides no capacity during the winter peak period.

In 1984, City Light entered into a power purchase and sales contract with the Districts under which it purchases all power generated by the Lucky Peak Project, 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 the Lucky Peak Project to a point of interconnection with the BPA transmission system.

City Light has typically exchanged the entire output of the Lucky Peak plant for winter energy and a premium. For calendar years 2014 and 2015, Shell Corp is the counterparty for the Lucky Peak exchange. There is not yet a contract for a 2016 exchange, so the forecast assumes an exchange with terms equivalent to those of 2015.

Stateline Wind Project
City Light purchases a percentage of the wind-generated power and associated renewable energy credits from the Stateline Wind Project in eastern Washington and Oregon. The contract terms are from July 1, 2004, through December 31, 2021, and City Light's share has a nameplate capacity of 175 MW.

City Light also entered into a related ten-year agreement with PacifiCorp to purchase integration and exchange services for all of City Light's share of the Stateline Wind Project output. Under this agreement, PacifiCorp delivers City Light's share of the Stateline Wind Project output to the Mid-C market hub two months after it is generated. The integration and exchange agreement with PacifiCorp terminates at the end of 2021.

Small Renewables

SMUD: In 2007 City Light began a seasonal exchange with Sacramento (CA) Municipal Utility District (SMUD), in which City Light provides scheduling and delivery services for up to 15 aMW of power at the California-Oregon border that SMUD purchases from the Sierra Pacific Industries (SPI) Burlington Biomass Facility, a renewable resource which burns wood waste and produces electrical energy. In exchange, City Light receives the value of up to 25 MW of winter energy from SMUD, which is financially settled. City Light purchases from SPI all of the renewable energy and environmental attributes associated with the resource in excess of 15 aMW, or about 4 aMW. The contract expires in 2017.

Columbia Ridge Landfill Gas: In December 2009, City Light began taking delivery of 6 aMW per year and associated renewable energy credits (RECs) from the Columbia Ridge Landfill Gas project in Arlington, Oregon. The plant burns methane produced by the decomposition of solid waste in the landfill and has 6.4 MW of generation capacity. The City sends its solid waste to the landfill. Waste Management Renewable Energy (WMRE) is the developer, owner and operator of the project. The contract has a 20-year term, with specific prices and escalation rates. City Light redirected some transmission paths, and has firm transmission for project output to City Light's retail load. In addition, in November 2012 City Light negotiated a separate contract with WMRE to buy an additional 6 aMW per year from this plant, which is expected to be available in August 2014.

King County West Point Treatment Plant: In 2010, City Light executed a power purchase agreement with King County for the output of a proposed cogeneration plant at the West Point Wastewater Treatment Facility in Seattle. The County declared commercial operation effective January 2014. The 4.6 MW plant is expected to provide about 2 aMW of electrical energy and associated renewable energy credits (RECs). The contract has specific prices and annual escalation and extends for 20 years after commercial operations begin.

Appendix B: Forecast-Budget Crosswalk

This appendix provides detail on the relationship between the costs in the budget and the financial forecast (revenue requirement). Budget and forecast treat these costs differently because they have two different objectives. The budget primarily sets spending authority, while the financial forecast estimates expenses for future compliance with City Light's financial policies.

In many instances the budget and the financial forecast expenses are the same. However, there are a number of expense categories where the two have different definitions and/or assumed values of expenses. The goal of this appendix is to explain how and why the two methods are different.

Summary

Table B.1 provides a high-level comparison of budgeted versus forecasted expenses, with notes detailing the differences. The major differences are:

- Lower BPA Power and Wheeling Costs
- Netting out short term purchased power from revenues
- $10M under-expenditure assumption in O&M and a 10% under-expenditure assumption in CIP

Table B.1
Forecast-Budget Crosswalk Summary

$ Millions	**2015 Budget**	**2016 Budget**	**2015 Forecast**	**2016 Forecast**	**2015 Difference**	**2016 Difference**
Operating Expenses						
Total Non-Power O&M	$319.3	$330.1	$239.1	$249.1	($80.2)	($80.9)
Long Term Purchased Power	296.5	312.4	268.4	274.8	(28.1)	(37.6)
Short Term Purchased Power	42.5	41.3	-	-	(42.5)	(41.3)
Taxes	90.3	93.5	97.9	101.6	7.5	8.2
Debt Service	200.5	210.8	194.0	204.7	(6.5)	(6.1)
Capitalized Expenses						
CIP	$391.2	$400.9	$363.4	$385.4	($27.7)	($15.4)
Deferred O&M	47.5	47.4	54.1	54.8	6.6	7.4
Adjust for CIP Labor Loadings	78.3	79.9	-	-	(78.3)	(79.9)
Adjust for AFUDC	4.1	6.0	-	-	(4.1)	(6.0)
Total Expenses, less Capital Loadings	**$1,305.2**	**$1,350.5**	**$1,216.8**	**$1,270.5**	**($88.4)**	**($80.0)**
Notes						
Total Non-Power O&M	See Table B.5 for detail					
LT Purchased Power	See Table B.2 for detail					
Short Term Purchased Power	Net wholesale revenue is forecast as a net revenue so it does not show up in expenses. The budget uses a conservative (higher than expected) purchased power value to provide the necessary budget authority in adverse water years.					
Taxes	The budget uses paid taxes, while the forecast uses accrued taxes. The forecast also includes bad debt in this category, which is not a budgeted expense. In addition, the budget includes taxes on suburban undergrounding revenue, which is included in deferred O&M in the financial forecast					
Debt Service	The forecast is net of federal interest subsidies while budget uses gross debt service. In addition, the budget includes debt issue costs, while the forecast does not include issue costs in debt service; instead these are netted from bond proceeds.					
CIP and Deferred O&M	See Tables B.6 and B.7 for detail					
Adjust for Labor Loadings and AFUDC	In the budget, labor loadings are allocated to CIP but are budgeted in O&M. Subtracting them avoids double counting when aggregating the CIP and O&M budget to compare the total expenses with the forecast. Likewise, AFUDC must be taken out of CIP since all interest expense is included in debt service category.					

Power Contracts

Table B.2 shows the differences between the power contracts forecast and the budget.

Table B.2
Power Contracts Forecast-Budget Crosswalk

$ Millions	2015 Budget	2016 Budget	2015 Forecast	2016 Forecast	2015 Difference	2016 Difference	Notes
Long-Term Purchased Power	**$251.9**	**$263.8**	**$231.9**	**$237.2**	**($20.0)**	**($26.6)**	
High Ross	22.2	22.2	13.1	13.1	(9.1)	(9.1)	$9.1 million is deferred in the financial forecast
BPA Costs	169.6	180.7	165.0	169.4	(4.6)	(11.3)	Budget includes higher inflation assumptions. Actual increases will be handled through the BPA pass through mechanism.
RECs	2.5	2.9	-	-	(2.5)	(2.9)	Forecast includes as non-power O&M
Upstream Storage Benefit	1.9	1.9	-	-	(1.9)	(1.9)	Forecast includes as non-power O&M
Grant County PUD	4.8	4.1	3.1	3.2	(1.7)	(0.9)	Budget includes Wanapum repair estimate
Green Up RECs	0.5	0.5	-	-	(0.5)	(0.5)	Forecast includes as non-power O&M
SPI SMUD	2.6	2.6	2.6	2.6	(0.0)	(0.0)	
GCPHA	5.9	5.9	5.9	6.1	0.0	0.1	
Lucky Peak	6.9	7.5	7.1	7.3	0.3	(0.1)	Minor adjustments when Budget was developed
Columbia Ridge	6.1	6.2	6.1	6.2	-	-	
Stateline	27.0	27.2	27.0	27.2	-	-	
King Co. West Point	2.0	2.0	2.0	2.0	-	-	
Wheeling	**$44.5**	**$ 48.6**	**$36.5**	**$37.6**	**($8.1)**	**($11.0)**	
BPA Firm Wheeling	42.3	46.6	37.3	38.4	(5.1)	(8.2)	See BPA note above
Savings	-	-	(2.0)	(2.0)	(2.0)	(2.0)	Forecast placeholder for power related savings (lower power and wheeling costs and/or higher power marketing revenue)
AC Intertie Ownership	1.3	1.0	-	-	(1.3)	(1.0)	Forecast includes as non-power O&M
Other Wheeling	0.3	0.3	0.2	0.2	(0.1)	(0.1)	Buffer in misc. transmission costs, not included in forecast
South Fork Tolt	0.4	0.4	0.4	0.4	0.0	0.0	
Columbia Grid	0.3	0.3	0.4	0.4	0.1	0.1	Budget was revised downward since Strategic Plan
Short Term Wheeling	-	-	0.2	0.2	0.2	0.2	Included in ST Purchased Power in budget
TOTAL Power Contract Costs	**$296.5**	**$312.4**	**$268.4**	**$274.8**	**($28.1)**	**($37.6)**	

Non-Power O&M

Tables B.3, B.4, and B.5 explain the annual changes in Non-Power O&M. Table B.3 presents the annual changes that were made to the budget, and Table B.4 provides more detail on the specific new initiatives (i.e., BIPs). Note that the 2016 changes shown are incremental to 2015.

Table B.5 lists the adjustments that are made to the O&M budget to get to the O&M forecast for the RRA.

Table B.3
2015 and 2016 Non-Power O&M Budget Changes

$ Millions	2014 Adopted	Inflation and Technical BIPs	BIPs	2015 Proposed	Inflation and Technical BIPs	BIPs	2016 Proposed
Office of Superintendent	$3.2	$0.3	$0.0	$3.5	$0.0	$0.0	$3.5
Power Supply	50.8	0.1	-	51.0	0.8	-	51.7
Conservation Resources and Environmental Affairs	61.4	0.6	(0.1)	61.9	1.1	(0.0)	63.0
Distribution Services	74.1	3.4	-	77.5	2.0	-	79.5
Customer Services	28.0	1.1	0.7	29.8	0.4	0.0	30.2
Human Resources	9.0	0.2	(0.0)	9.2	0.1	(0.0)	9.3
Financial Services	36.7	2.2	1.2	40.1	2.2	0.0	42.3
General Expenses	88.1	1.9	0.3	90.3	4.0	0.0	94.3
Compliance and Security	3.4	0.2	-	3.6	0.0	-	3.7
Total O&M Budget	**$354.8**	**$9.9**	**$2.0**	**$366.8**	**$10.7**	**$0.1**	**$377.5**

Table B.4
2015 and 2016 Budget Issue Paper Detail

BCL Name	BIP	BIP Title	BIPS 2015	BIPS 2016
			$ Millions	
Conservation Resources and Environmental Affairs O&M	SCL-105	Temporary/'Contract-in' conversion to Permanent Positions BIP	($0.1)	($0.0)
Customer Services	SCL-101	Call Center Combined BIP	0.7	0.0
Customer Services	SCL-105	Temporary/'Contract-in' conversion to Permanent Positions BIP	(0.0)	(0.0)
Human Resources	SCL-105	Temporary/'Contract-in' conversion to Permanent Positions BIP	(0.0)	(0.0)
Financial Services	SCL-103	Enterprise Architecture	0.2	0.0
Financial Services	SCL-104	IT Software Maintenance Cost Increase	1.1	0.0
Financial Services	SCL-105	Temporary/'Contract-in' conversion to Permanent Positions BIP	(0.1)	(0.0)
General Expenses	SCL-105	Temporary/'Contract-in' conversion to Permanent Positions BIP	0.2	0.0
General Expenses	SCL-504	IT Security Upgrades and Cyber Security	0.1	0.0
Total			**$2.0**	**$0.1**

Table B.5

2015 and 2016 Non-Power O&M Budget Forecast Crosswalk Detail

City Light Budget to Forecast O&M Cross-Walk					
			2014 Adopted	**2015 Proposed**	**2016 Proposed**
Reference			**2014**	**2015**	**2016**
A		**Total Non-Power O&M in Budget**	**$307.4**	**$319.3**	**$330.1**
B	add	REC and Intertie Expense in Purchased Power Budget	2.7	4.6	5.6
C	add	PNCA Payments in Purchased Power Budget	1.9	1.9	1.9
D	less	Capital Loadings	78.3	76.8	78.4
E	less	Assumed Budget Under-Expenditures	-	10.0	10.0
	equals	**Non-Power O&M for Financial Forecast**	**$233.7**	**$239.1**	**$249.1**
		Non Power O&M in 2015-2016 RRA	237.5	239.3	247.0
F		**Difference from Adjusted Budget**	**($3.9)**	**($0.2)**	**$2.1**
Notes					

General	The structure of the O&M categories used in the Financial Forecast are set by FERC based accounting standards, which are used to track financial actuals and calculate financial metrics such as debt service coverage. This is the fundamental reason why the O&M in the budget needs to be adjusted to meet the structure of the financial forecast.
A	This is the Total Direct Non-Power O&M in Budget (excludes all Deferred O&M, Purchased Power, Taxes, Debt Service and CIP).
B	REC Purchases and Intertie O&M are budgeted in Purchased Power. However, in the Financial Forecast they are included in Other Power Costs and Transmission, respectively. Therefore, they need to be included in total Non-Power O&M for the financial forecast.
C	Payments related to the Pacific Northwest Coordination Agreement (PNCA) are budgeted in purchased power but recorded as a Generation expenses in the Financial Forecast. These expenses are related to the compensation for the benefits of upstream storage received at City Light's Boundary facility.
D	This is the portion of Non-Power O&M that is forecasted to be overhead expenses associated with the planned levels of CIP and Deferred O&M. Overhead Expenses include paid time off, fringe benefits, material handling, transportation use, shop handling and A&G. Overhead Expenses are capitalized and not included in Non-Power O&M in the Financial Forecast. They are implicit in the values of CIP and deferred O&M in the financial forecast. These are only estimates; actual capitalized overheads are determined by cost accounting.
E	Historically, the entire O&M Budget has not been fully spent. As part of the 2014 Strategic Plan a $10 million or roughly 3% under-expenditure assumption was used for rate setting purposes
F	The 2015 and 2016 values reflect the differences in the O&M assumptions in the 2014 Strategic Plan and in the 2015-2016 Proposed Budget. The Proposed budget was finalized after the Strategic Plan was developed and reflects actual inflation levels adopted by the City's Central Budget Office. The 2014 value reflects the differences between assumptions in the 2014 Adopted Budget and the 2014 Adopted RRA.

Capital Improvement Program and Deferred O&M

Table B.6 shows how the CIP differs between the budget and the forecast, while Table B.7 explains the differences in deferred O&M.

Table B.6
CIP Crosswalk between Budget and Forecast

$ Millions	**2015 Budget**	**2016 Budget**	**Notes**
CIP (allocations)	**$391.2**	**$400.9**	CIP in 2015-2016 Proposed Budget
Lifetime Appropriation Carry Forwards	33.5	2.7	Expenditures carried forward from the previous year budget
AFUDC*	(4.1)	(6.0)	No AFUDC is assumed in the CIP in the financial forecast
Cash Flow Adjustments	(33.4)	7.7	Adjustments for differences in cash spending vs. budgeting for selected projects
Under Expenditure Assumption	(38.7)	(40.5)	Forecast assumes only 90% of CIP will be spent.
Subtotal 2015 Proposed CIP	**$348.4**	**$364.7**	Total Cash spending assumed for 2015-2016 Proposed Budget
Adjustments	15.0	20.7	Since the Strategic Plan was developed there have been scheduling changes and cost revisions for some projects. Over the next 6 years total spending levels for the 6-year 2015 Proposed CIP Plan are very close to that assumed in the 2014 Strategic Plan, but individual years may differ.
CIP in Strategic Plan / RRA	**$363.4**	**$385.4**	Total Cash Spending Assumed in the 2014 Adopted Strategic Plan and the 2015 and 2016 RRA

* AFUDC (Allowance for Funds Used During Construction) refers to capitalizing the interest costs that are part of the cost of acquiring certain assets. The financial forecast does not include these costs as part of capital expenses for purposes of developing the revenue requirement. AFUDC is a reduction to accrued interest expense on the income statement.

Table B.7
Deferred O&M Crosswalk between Budget and Forecast

$ Millions	2015 Budget	2016 Budget	2015 Forecast	2016 Forecast	2015 Difference	2016 Difference
Deferred O&M						
Programmatic Conservation	$36.9	$36.8	$39.8	$40.9	$2.8	$4.1
Environmental Mitigation and Misc.	10.6	10.6	5.2	4.7	(5.4)	(5.9)
High Ross			9.1	9.1	9.1	9.1
Total	**$47.5**	**$47.4**	**$54.1**	**$54.8**	**$6.6**	**$7.4**
Notes						
Programmatic Conservation	The forecast includes labor loadings and also payment lags for multi-year programs					
Environmental Mitigation and Misc.	The Budget includes a placeholder budget authority of $10.2M for Environmental Cleanup, whereas the forecast includes an estimated spending amounts of around $4 million in 2015 and $3 million in 2016. Also, the forecast reflects labor loadings and payment timing lags on relicensing mitigation measures at the Skagit Facilities.					
High Ross	The Budget Does not defer any of High Ross Payments					

Appendix C: Capital Expenditures and Funding Sources

Capital Expenditures

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 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 a rigorous utility-wide prioritization process 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.

Table C.1 shows Proposed 2015-2020 CIP, other deferred costs, and funding sources. A discussion of each of the subsections in table C.1 follows. The Proposed 2015 CIP plan differs slightly from the CIP assumed in the 2014 Strategic Plan Update due to some timing changes in a number of projects. The difference is shown in the "Adjustments" line in Table C.1. While individual years may be different the total over the 6 years is only $7.3 million.

Tables C.2 to C.9 provide additional detail by breaking out the CIP costs by individual project.

Table C.1
Total Capital Expenditures and Funding Sources

$ Millions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Central Utility Projects							
Customer and Billing	$5.4	$3.8	$0.2	$0.0	$0.0	$0.0	$9.4
Finance and IT Systems	8.6	8.7	7.4	7.7	9.5	9.6	51.5
Fleets and Facilities	18.0	18.3	10.2	10.4	25.4	48.5	130.9
Subtotal	$32.0	$30.8	$17.8	$18.1	$34.9	$58.1	$191.8
Distribution							
Substations	$45.8	$55.0	$43.0	$20.7	$20.2	$21.8	$206.5
Network	21.6	37.0	34.9	23.1	22.8	27.5	166.9
Radial	55.4	53.5	52.5	45.9	49.3	50.2	306.9
Service Connections	50.7	64.3	60.7	39.1	33.7	34.3	282.8
Distribution Other	19.8	14.0	12.8	9.8	14.7	14.5	85.6
Subtotal	$193.3	$223.8	$203.9	$138.6	$140.7	$148.3	$1,048.7
External Projects							
Local Jurisdictions	$19.4	$11.7	$11.6	$11.5	$12.5	$15.3	$81.9
Transportation Relocations	39.8	17.4	10.6	10.7	6.6	4.6	89.7
Customer Other	0.5	0.0	0.0	0.0	4.2	4.3	9.1
Subtotal	$59.8	$29.2	$22.2	$22.2	$23.2	$24.1	$180.7
Power Supply							
Boundary	$30.8	$36.1	$35.7	$42.4	$34.8	$40.2	$220.0
Skagit	19.4	27.4	38.2	26.2	15.2	24.4	150.8
Cedar Falls - Tolt	1.8	1.6	1.3	2.0	2.3	6.2	15.2
Power Supply Other	3.4	3.3	3.0	2.9	2.9	3.0	18.4
Subtotal	$55.3	$68.4	$78.2	$73.5	$55.2	$73.8	$404.4
Transmission							
Total	$8.0	$12.6	$11.3	$10.1	$23.5	$20.2	$85.7
Total 2015 Proposed CIP Plan	**$348.4**	**$364.7**	**$333.5**	**$262.5**	**$277.5**	**$324.7**	**$1,911.2**
Adjustments	$15.0	$20.7	-$62.4	-$26.5	$41.1	$19.3	$7.3
CIP in 2014 Adopted Strategic Plan	$363.4	$385.4	$271.1	$235.9	$318.6	$343.9	$1,918.5
Conservation	$39.8	$40.9	$42.1	$43.3	$44.6	$45.9	$256.7
Environmental Mitigation Deferred O&M Costs	1.5	1.5	1.5	1.6	1.6	1.6	9.3
Toxic Cleanup Deferred O&M Costs	3.8	2.8	5.6	5.7	5.8	6.0	29.7
Deferred High Ross	9.1	9.1	9.1	9.1	9.1	9.1	54.6
Deferred Taxes	-	0.42	-	-	-	-	0.4
Total Funds Required	**$54.1**	**$54.8**	**$58.3**	**$59.7**	**$61.1**	**$62.6**	**$350.7**
Sources of Funds	**$417.5**	**$440.2**	**$329.4**	**$295.7**	**$379.8**	**$406.5**	**$2,269.1**
Cash From Operations	109.4	97.1	103.8	110.6	112.7	117.0	650.6
Cash From Contributions	32.3	39.0	28.8	27.6	23.9	24.2	175.9
Cash From Bond Sale	274.6	227.9	197.0	192.7	265.4	206.4	1,363.8
Cash From the Working Capital Account	1.2	76.2	(0.1)	(35.2)	(22.3)	58.9	78.7
Total Funds Available	**$417.5**	**$440.2**	**$329.4**	**$295.7**	**$379.8**	**$406.5**	**$2,269.1**

Power Supply. Power Supply includes generation facilities; typical assets would be reservoirs, dams, waterways, waterwheels, turbines, generators and accessory electrical equipment. Generation expenditures are projected to total $404.4 million during the six-year planning period, averaging about $67.4 million per year and representing about 21% of total CIP. A large percentage of generation investment is dedicated to core utility functions that maintain or add to generation infrastructure and ensure system reliability and power availability to customers. City Light continuously invests in generator and turbine runner rebuild programs ($48 million at Boundary and $35 million at Skagit). This also includes requirements primarily related to federal relicensing, including relicensing the Boundary Project ($106 million) and Endangered Species Act mitigation ($6 million). Boundary Relicensing costs have been part of the CIP since 2013, before that they were categorized as deferred O&M.

Transmission. Transmission plant includes poles, towers and conductors used to carry electricity from generation facilities to substations. Transmission expenditures are projected to total $85.7 million during the six-year planning period, averaging about $14.3 million per year and representing about 4.5% of total CIP. The transmission reliability project ($15.4 million) supports engineering, construction, and other work necessary to improve or maintain the reliability of the overhead or underground transmission system. Reliability projects include line rebuilds, new lines to enhance reliability of a substation, new line configurations to improve operation, and relocations required to maintain the transmission system. Another large project is the Denny Substation Transmission Lines project ($45.5 million), which designs and constructs transmission lines to support the new North Downtown Substation. Investments are also needed to relocate transmission facilities at the request of other agencies ($3.1 million). Relocations are necessitated by road realignments, construction of facilities, regional upgrades, and changes in lighting.

Distribution. Distribution plant includes poles, wires and cables, transformers, manholes, vaults, ducts, and other electrical equipment and infrastructure needed to deliver power from substations to the customer connection. Distribution CIP totals about $1.048 billion during the six-year planning period, averaging $174.8 million per year and representing about 55% of total CIP. Significant projects include: the new Denny Substation ($84.4 million), substation equipment improvements ($31.1 million), and replacements of aging overhead ($120.1 million) and underground ($36.1 million) equipment.

Central Utility. These expenses are related to General Plant and include investments in non-electrical system assets including buildings and facilities, such as the North and South Service Centers, and investments in office-related computer equipment, information and communications systems, furniture, and mobile equipment. Expenditures of $191.8 million provide for general plant improvements and/or replacement over the six-year planning period, averaging about $32.0 million per year and representing about 10% of total CIP. This total includes various Finance and IT systems ($51.5 million), fleets and facilities ($130.9 million), which includes fleet replacements ($31.8 million), a technical training center ($10.2 million), the Service Center Development Project ($37.8 million), as well as a new customer billing and information system (NCIS) ($9.4 million).

External Projects. These projects include work related to relocating infrastructure for transportation projects, investments in streetlight assets and various undergrounding work. Over the six-year planning period, these expenses total $180.7 million, which averages to $30.1 million per year and accounts for around 9.5% of all CIP. The most prominent project is the Alaska Way Viaduct and Seawall Replacement, which is projected to total $61.1 million. There are four projects related to streetlight investments, totaling $75.0 million. Investments in streetlight infrastructure (e.g. LED conversion) are allocated directly to streetlight customer rates. Therefore, the cost of these investments separated from the rest of the CIP.

Other Capitalized Expenditures (Deferred O&M)
Conservation. Conservation resource programs offer financial incentives (such as rebates, discounts and loans) for the installation of approved energy-saving equipment or weatherization measures and for building that exceed energy code requirements. Program costs include program administration, audits and inspections, and the design and installation of energy savings measures. The six-year conservation forecast maintains the annual new energy savings target of 14.0 aMW, and the estimated cost of achieving these savings is reflected in the financial forecast.

High Ross Payment Amortization. In setting rates for 2000-2003, City Council directed the amortization of a portion of the annual High Ross payment. City Light pays B.C. Hydro $21.8 million annually from 2000 through 2020; $9.1 million is capitalized, and $12.7 million is expensed. From 2021 through 2035, the remaining balance of deferred costs will be amortized.

Relicensing, Mitigation and Other Costs. Certain operating expenses associated with relicensing and environmental mitigation are amortized; these expenditures are projected to total $9.3 million over the six-year planning period. Deferred mitigation expenses that differ from those in the CIP because they are for mitigation on land or structures which are not City Light owned assets. Asset owners include a variety of nonprofit organizations and governmental agencies with which City Light has entered into contracts for environmental mitigation pursuant to the terms of relicensing settlement agreements. Other deferred costs include debt expense and studies related to future capital projects.

Environmental (Toxic) Cleanup. Per Council direction, since 2013 expenses related to interagency environmental remediation projects are amortized. City Light pays a portion of the total project costs for environmental damage caused by historical utility operations; the majority of these expenses are related to Duwamish Waterway cleanup. The total payments expected over the 6 years are estimated to be $29.7 million, but are subject to significant uncertainty.

Deferred Taxes. City Light defers taxes related to the revenue that is recorded when a phase of a suburban undergrounding project is completed.

Funding Sources

Capital requirements of $2.1 billion from 2013 through 2018 (including $1.7 billion of the CIP and $348.0 million of certain capitalized other costs) are expected to be financed through a combination of cash from operations (net revenues), contributions in aid of construction (CIAC), reimbursement of costs for transportation-related projects, external conservation funding, and the proceeds of future bonds.

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. 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.

Cash from Contributions. Cash from Contributions is a source of cash that cannot be counted on to pay debt service expenses. This category of cash, given planned expenses, affects the amount borrowed and, thereby, affects future debt service requirements and future rates.

Cash from Bond Sale. Cash from Bond Sale is not available to pay debt service costs and, therefore, does not affect the revenue requirements for the current rate year. The amounts borrowed, affect future debt service requirements and future rates. Bond Sales shown are net of bond issue costs and any transfers of bond proceeds into the bond reserve account.

Cash from Working Capital Account. These are funds earned in previous years that are spent in the current year or funds earned in the current year that are carried forward to future years.

Table C.2
Central Utility Projects CIP Detail

$ Millions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Central Utility Projects	**$32.0**	**$30.8**	**$17.8**	**$18.1**	**$34.9**	**$58.1**	**$191.8**
E1: Customer and Billing	**5.4**	**3.8**	**0.2**	**0.0**	**0.0**	**0.0**	**9.4**
9937: Customer Information System	5.4	3.8	0.2	0.0	0.0	0.0	9.4
E2: Finance and IT Systems	**$8.6**	**$8.7**	**$7.4**	**$7.7**	**$9.5**	**$9.6**	**$51.5**
9915: Information Technology Infrastructure	2.9	3.3	3.4	3.5	6.2	6.7	25.9
9933: Enterprise Performance Management	0.7	0.7	0.0	0.0	0.0	0.0	1.4
9959: Inventory System Redevelopment	0.0	0.0	0.0	0.0	0.0	0.0	0.0
9960: IT Security Upgrades	1.3	0.8	0.7	1.2	1.2	1.2	6.4
9961: Summit FinMap Upgrade - City Light	0.4	0.4	0.0	0.0	0.0	0.0	0.8
9962: Enterprise Document Management System	2.1	2.0	2.0	1.7	1.7	1.7	11.3
9970: PeopleSoft Reimplementation - City Light	1.2	1.4	1.4	1.4	0.4	0.0	5.6
E3: Fleets and Facilities	**$18.0**	**$18.3**	**$10.2**	**$10.4**	**$25.4**	**$48.5**	**$130.9**
8389: Special Work Equipment - Shops	0.3	0.3	0.3	0.3	0.0	0.0	1.1
9006: Safety Modifications	1.1	1.2	1.2	1.2	1.2	1.2	7.2
9007: Miscellaneous Building Improvements	1.0	1.0	1.1	1.1	1.3	2.6	8.1
9072: Building Envelope Upgrades	1.4	1.3	1.3	1.3	1.1	1.2	7.6
9101: Equipment Fleet Replacement	3.9	4.1	2.8	3.7	8.2	9.2	31.8
9103: Office Furniture and Equipment Purchase	0.5	0.5	0.6	0.6	1.0	1.0	4.3
9107: North and South Service Center Improvements	0.4	0.2	0.3	0.2	0.7	3.6	5.5
9134: Seismic Mitigation	0.0	0.0	0.1	0.0	0.1	0.1	0.3
9151: Facilities Regulatory Compliance	0.3	0.4	0.3	0.3	0.3	0.3	2.0
9152: Environmental Safeguarding and Remediation of Facilities	0.0	0.0	0.0	0.0	0.0	0.1	0.3
9156: Facilities Infrastructure Improvements	0.3	0.3	0.3	0.3	0.1	0.1	1.5
9159: Workplace and Process Improvement	0.9	1.0	1.0	0.2	0.8	1.0	4.9
9161: Substation Comprehensive Improvements	0.2	0.2	0.2	0.2	0.2	0.2	1.2
9215: South Service Center Spokane Exit Modification	0.4	0.0	0.0	0.0	0.0	0.0	0.4
9220: North Service Center Interim Work	2.1	0.0	0.0	0.0	0.0	0.0	2.1
9230: Technical Training Center Development	3.5	6.7	0.0	0.0	0.0	0.0	10.2
9231: Bothell Substation Environmental Remediation	1.2	0.4	0.0	0.0	0.0	0.0	1.6
9232: Service Center Development Project	0.0	0.0	0.0	0.0	9.8	28.0	37.8
9320: Energy Conservation	0.4	0.7	0.8	0.8	0.5	0.0	3.2

Table C.3
Distribution Projects CIP Detail

$ Millions	2015	2016	2017	2018	2019	2020	Total
Distribution	**$193.3**	**$223.8**	**$203.9**	**$138.6**	**$140.7**	**$148.3**	**$1,048.7**
C1: Substations	**$45.8**	**$55.0**	**$43.0**	**$20.7**	**$20.2**	**$21.8**	**$206.5**
7121: Replace Breakers BPA Covington and MV Substations	0.0	0.0	0.0	0.0	0.0	0.0	0.1
7750: Substation Plant Improvements	0.7	0.7	0.8	0.8	0.8	0.7	4.6
7751: Substation Capacity Additions	1.8	1.2	1.5	1.7	1.8	2.4	10.4
7752: Substation Equipment Improvements	6.1	3.8	4.5	5.0	5.9	5.9	31.1
7753: Relaying Improvements	4.1	3.7	3.5	4.0	4.8	4.8	25.0
7755: Substations Demand Driven Improvements	0.0	0.0	0.0	0.0	0.0	0.0	0.0
7756: Interbay Substation - Development	0.0	0.0	0.0	0.0	0.1	0.1	0.2
7757: Denny Substation Development	22.4	36.0	26.0	0.0	0.0	0.0	84.4
7776: Substation Transformer Replacements	0.2	4.1	0.3	4.1	0.6	1.2	10.5
7779: Substation Breaker Replacements and Reliability Additions	5.0	4.4	5.4	4.0	4.9	5.4	29.0
7783: Substations Oil Containment	0.3	0.3	0.3	0.3	0.3	0.3	1.7
7811: East Pine Substation - Transformer Replacements	4.4	0.3	0.0	0.0	0.0	0.0	4.7
8424: Substation Automation	0.7	0.6	0.8	0.8	0.9	0.9	4.8
C2: Network	**$21.6**	**$37.0**	**$34.9**	**$23.1**	**$22.8**	**$27.5**	**$166.9**
8129: Network Hazeltine Upgrade	0.5	0.6	0.5	0.5	0.5	0.7	3.2
8130: Network Maintenance Hole and Vault Rebuild	1.8	1.8	3.0	3.1	3.1	3.1	15.8
8201: Union Street Substation Networks	1.3	2.1	2.2	2.3	2.3	2.4	12.6
8202: Massachusetts Street Substation - Networks	2.5	2.7	3.6	3.6	3.7	4.0	20.0
8203: Broad Street Substation - Network	2.0	7.8	11.5	7.5	3.2	4.0	36.0
8301: First Hill - Network	1.9	2.2	2.3	2.4	2.4	2.4	13.6
8404: Denny Substation - Network	10.7	19.5	11.5	3.5	3.1	5.4	53.7
8407: First Hill - Network Load Transfer	0.0	0.0	0.0	0.0	4.1	5.0	9.1
8464: University Substation - Network	0.9	0.4	0.3	0.3	0.3	0.4	2.8
C3: Radial	**$55.4**	**$53.5**	**$52.5**	**$45.9**	**$49.3**	**$50.2**	**$306.9**
8322: Dallas Ave. 26 kV Crossing	1.4	0.3	0.0	0.0	0.0	0.0	1.7
8351: Overhead Equipment Replacements	18.4	19.5	21.8	19.1	20.5	20.7	120.1
8353: Underground Equipment Replacements	9.7	6.8	5.3	4.5	4.8	5.1	36.1
8355: Overhead Customer Driven Capacity Additions	2.8	3.2	3.4	3.4	4.4	4.4	21.6
8356: Overhead System Capacity Additions	2.3	2.2	2.3	2.3	2.2	2.3	13.7
8358: Overhead 26kV Conversion	1.7	1.8	1.4	1.4	1.4	1.4	9.2
8360: Underground Customer Driven Capacity Additions	2.6	2.6	1.9	2.0	2.1	2.0	13.2
8361: Underground System Capacity Additions	2.3	2.4	2.5	2.6	2.6	2.1	14.6
8362: Underground 26kV Conversion	1.5	1.5	1.5	1.8	2.2	2.2	10.7
8373: Laurelhurst - Underground Rebuild	1.3	1.0	0.0	0.0	0.0	0.0	2.3
8425: Distribution Automation	1.8	2.9	4.0	2.0	2.5	2.6	15.8
8429: Mobile Workforce Implementation	2.3	2.3	1.6	0.0	0.0	0.0	6.1
8452: Pole Attachment Requests Preparation Work	2.6	3.1	3.2	3.3	3.3	3.7	19.2
8463: PCB Transformer Replacement	1.1	1.3	1.2	1.2	0.7	0.7	6.1
8465: Broadband - City Light	2.3	2.3	2.5	2.4	2.5	2.8	14.8
9950: Automated Utility Design Implementation	1.3	0.3	0.0	0.0	0.0	0.0	1.6

Table C.4
Distribution CIP Detail (continued)

$ Millions	2015	2016	2017	2018	2019	2020	Total
Distribution (cont.)							
C4: Service Connections	**$50.7**	**$64.3**	**$60.7**	**$39.1**	**$33.7**	**$34.3**	**$282.8**
8054: Meter Additions	2.6	2.1	1.9	1.6	1.3	1.1	10.7
8350: Overhead Outage Replacements	0.3	0.2	0.3	0.3	0.4	0.6	2.1
8352: Underground Outage Replacements	1.0	1.0	1.0	1.0	1.4	1.9	7.3
8363: Network Additions and Services: Broad Street Substation	5.7	8.3	5.7	5.8	5.9	6.1	37.4
8364: Network Additions and Svcs: First Hill, Mass, Union & Univer	4.9	1.8	2.7	2.7	2.7	2.8	17.6
8365: Large Overhead and Underground Services	3.2	2.6	2.6	2.7	3.8	2.9	17.9
8366: Medium Overhead and Underground Services	9.7	8.9	8.9	8.8	9.3	10.0	55.5
8367: Small Overhead and Underground Services	5.4	5.6	5.6	5.7	5.8	5.2	33.3
8379: Normal Emergency	0.4	0.4	0.5	0.5	0.5	1.0	3.4
8380: Major Emergency	0.1	0.1	0.1	0.1	0.1	0.3	0.8
8405: Network Additions and Services - Denny	1.4	1.5	2.4	2.5	2.5	2.3	12.6
8426: Advanced Metering Infrastructure	16.0	31.7	29.0	7.3	0.0	0.0	84.1
C5: Distribution Other	**$19.8**	**$14.0**	**$12.8**	**$9.8**	**$14.7**	**$14.5**	**$85.6**
9009: Communications Improvements	1.3	1.0	0.9	0.8	0.8	0.8	5.6
9102: Special Work Equipment - Other Plant	0.9	1.0	1.0	1.0	1.0	1.1	6.0
9108: Transmission & Generation Radio Systems	0.4	0.3	1.2	1.2	0.7	0.1	3.8
9202: Security Improvements	6.5	4.0	2.8	2.0	2.0	2.1	19.5
9307: Distribution Area Communications Networks	1.4	1.1	1.0	2.5	2.3	2.6	10.9
9943: Network Geographic Information Systems	0.1	-	(0.0)	0.0	(0.0)	(0.0)	0.1
9952: Transformer and Network Load Management Tools Upgrade	0.0	-	0.0	0.0	0.0	0.0	0.0
9956: Energy Management System	7.1	4.9	3.7	-	-	-	15.7
9957: Enterprise Geographic Information System	1.4	1.8	2.2	2.2	-	-	7.6
9963: Federal and Regional Reliability Standards Compliance	0.0	-	-	-	-	-	0.0
9965: Tool Room Automation	0.6	-	-	-	-	-	0.6
9966: Distribution Management System	-	-	-	-	4.8	6.8	11.6
9968: Asset Investment and Optimization	-	-	-	-	3.0	1.0	4.1

Table C.5
External Projects CIP Detail

$ Millions	2015	2016	2017	2018	2019	2020	Total
External Projects	**$59.8**	**$29.2**	**$22.2**	**$22.2**	**$23.2**	**$24.1**	**$180.7**
D1: Local Jurisdictions	**$19.4**	**$11.7**	**$11.6**	**$11.5**	**$12.5**	**$15.3**	**$81.9**
8320: Shoreline Undergrounding: North City and Aurora Avenue North	6.7	0.1	-	-	-	-	6.8
8377: Transportation Streetlights	1.6	0.7	0.5	0.5	0.5	1.5	5.4
8378: Streetlights: Arterial, Residential and Floodlights	3.2	3.0	3.1	3.2	3.4	3.9	19.8
8403: Citywide Undergrounding Initiative - City Light	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8441: Streetlight LED Conversion Program	5.2	5.2	5.2	4.9	5.5	6.3	32.3
8460: Streetlight Infrastructure Replacement	2.7	2.7	2.8	2.9	3.0	3.6	17.6
D2: Transportation Relocations	**$39.8**	**$17.4**	**$10.6**	**$10.7**	**$6.6**	**$4.6**	**$89.7**
8307: Alaska Way Viaduct and Seawall Replacement - Utility Relocs	33.5	12.2	7.5	7.4	0.5	-	61.1
8369: Transportation Driven Relocations	2.2	2.2	1.9	2.1	5.0	3.4	16.7
8427: Sound Transit Northlink - City Light	1.7	2.5	1.2	1.2	1.1	1.2	8.8
8435: State Route 520 Bridge Relocations	0.5	-	-	-	-	-	0.5
8442: First Hill Connector Streetcar	0.1	0.1	-	-	-	-	0.2
8443: Mercer Corridor West Phase Relocations	0.8	0.4	0.1	-	(0.0)	(0.0)	1.3
8450: Sound Transit Light Rail East Link - City Light	0.9	0.0	-	-	-	-	1.0
D3: Customer Other	**$0.5**	**$0.0**	**$0.0**	**$0.0**	**$4.2**	**$4.3**	**$9.1**
8383: Neighborhood Voluntary Undergrounding Program	0.0	0.0	0.0	0.0	0.0	0.0	0.1
8430: Creston-Nelson to Intergate East Feeder Installation	0.5	0.0	0.0	-	-	-	0.6
9969: Enterprise Software Solution Replacement Strategy	-	-	-	-	4.2	4.3	8.4

Table C.6
Power Supply CIP Detail

$ Millions	2015	2016	2017	2018	2019	2020	Total
Power Supply	**$55.3**	**$68.4**	**$78.2**	**$73.5**	**$55.2**	**$73.8**	**$404.4**
A1: Boundary	**$30.8**	**$36.1**	**$35.7**	**$42.4**	**$34.8**	**$40.2**	**$220.0**
6343: Boundary Dam - Instrumentation Upgrade and Integration	0.9	0.1	-	-	-	0.0	1.0
6351: Boundary Powerhouse - Unit 51 Generator Rebuild	-	-	-	1.1	2.4	8.1	11.5
6353: Boundary Powerhouse - Unit 54 Generator Rebuild	-	1.9	5.7	6.0	2.2	-	15.8
6354: Boundary Powerhouse - Unit 56 Generator Rebuild	5.6	0.2	-	-	-	-	5.7
6401: Boundary Facility - Minor Improvements Program	2.2	2.5	10.0	0.1	2.6	9.2	26.7
6432: Boundary Facility - Electrical System Upgrades	-	0.2	0.0	-	-	-	0.2
6485: Boundary Powerhouse - Transformer Bank Rockfall Mitigation	0.0	0.1	0.1	0.1	0.2	0.1	0.5
6490: Boundary Powerhouse - Unit 56 Turbine Runner Replacement	2.7	0.1	-	-	-	-	2.8
6493: Boundary Switchyard - Generator Step-up Transformers	1.0	4.8	1.1	5.0	5.2	6.7	23.7
6533: Boundary - New Unit - 57	-	-	0.1	0.2	1.0	1.2	2.5
6535: Boundary Powerhouse - Unit 52 Generator Rebuild	-	-	1.1	2.3	6.3	6.6	16.3
6565: Landis and Gyr RTU Modernization Boundary, CF, Skagit	-	0.6	0.3	0.2	-	-	1.1
6566: Boundary - DC Battery System & Charge Modernization	0.4	0.5	-	-	-	-	0.8
6601: Boundary Entrance Improvements	1.0	0.1	-	-	-	-	1.1
6602: Boundary U55 Exciter replacement	0.2	1.4	0.2	0.2	-	-	1.9
6603: Boundary U56 Exciter Replacement	-	1.7	0.5	-	-	-	2.3
6987: Boundary - Licensing Mitigation	16.8	22.0	16.8	27.1	14.8	8.5	106.0

Table C.7
Power Supply CIP Detail (continued)

$ Millions	2015	2016	2017	2018	2019	2020	Total
A2: Skagit	**$19.4**	**$27.4**	**$38.2**	**$26.2**	**$15.2**	**$24.4**	**$150.8**
6224: Gorge Powerhouse - Transformer Bank 10 Replacement	0.1	-	-	-	-	-	0.1
6232: Skagit - Sewer System Rehabilitation	1.3	1.6	1.8	-	-	-	4.6
6326: Gorge Powerhouse - Fire Protection Improvements	0.1	0.1	0.3	0.2	0.1	0.1	0.8
6373: Ross Dam - AC/DC Distribution System Upgrade	(0.1)	1.1	2.5	0.6	-	0.0	4.2
6376: Ross Powerhouse - Programmable Language Controller Upgrade	0.2	0.3	0.3	-	-	-	0.7
6405: Skagit Facility - Minor Improvements Program	4.9	4.0	5.1	4.9	5.0	9.2	33.0
6415: Skagit Powerhouses - Install Protection Relays	0.4	0.8	0.4	0.2	-	-	1.8
6422: Diablo Powerhouse - Rebuild Generator Unit 31	0.0	2.2	9.0	5.0	2.3	0.1	18.6
6423: Diablo Powerhouse - Rebuild Generator Unit 32	2.0	6.7	6.7	1.1	-	-	16.5
6452: Ross Dam - New Access Road from SR20 to Dam	-	-	-	-	-	2.5	2.5
6457: Diablo Facility - Incline Lift Rehabilitation	-	-	-	-	-	0.0	0.0
6471: Diablo Powerhouse - Crane Wheel Replacements	0.4	-	-	-	-	-	0.4
6479: Newhalem - Generator 20/Support Facility Rebuild	0.6	-	-	-	-	-	0.6
6481: Diablo Facility - Storage Building	0.6	-	-	-	-	-	0.6
6483: Diablo Facility - Lines Protection Upgrades	1.5	0.5	-	-	-	-	2.0
6514: Skagit - Babcock Creek Crossing	0.6	0.0	-	-	-	-	0.6
6515: Skagit - Facilities Energy Conservation Program	0.9	2.8	-	-	-	-	3.8
6516: Ross Rock Slide Area Improvements	0.9	0.1	0.0	-	0.0	-	1.0
6520: Skagit Facilities Plan	1.3	2.1	1.7	-	(0.0)	0.0	5.0
6532: Diablo Load Interrupters Replacement	-	0.7	1.0	1.0	-	-	2.8
6540: Skagit Boat Facility Improvements	0.3	1.2	0.5	-	-	-	2.0
6541: Ross Powerhouse - Replace Transformer Banks 42 and 44	1.5	0.3	5.7	-	-	-	7.5
6561: Newhalem Backup Center	0.3	0.2	-	-	-	-	0.6
6562: Ross Governors	0.5	0.9	0.7	-	-	-	2.1
6564: Ross Exciters 41 - 44	-	0.2	1.0	1.1	0.0	-	2.3
6577: Ross - Powerhouse Rockfall Mitigation	-	-	0.1	0.4	0.0	4.1	4.6
6578: Gorge - Switchyard 230 kV Wrought Iron Bus Replacement	0.1	0.1	0.1	-	-	-	0.4
6580: Ross - 480V AC Station Service Switchgear Replacement	-	0.1	0.1	4.9	-	-	5.1
6581: Gorge - 240V AC Station Service Switchgear Replacement	-	-	-	0.1	0.4	-	0.5
6582: Ross - R1 and R2 Relay and Instrumentation Upgrade	-	-	0.1	0.1	0.4	0.1	0.7
6583: Skagit - DC Battery System & Charge Modernization	0.2	0.2	0.2	-	-	-	0.7
6584: Diablo - Replace AC Panels	0.2	0.5	-	-	-	-	0.6
6585: Ross - Silvacell Nozzle Retrofit	0.1	0.3	0.4	-	-	-	0.8
6586: Ross - Oil Vapor Reduction @ Turbine Guide	0.3	0.2	0.2	-	-	-	0.6
6588: Diablo - Incline Rehabilitation	-	-	-	0.1	2.1	2.1	4.3
6589: Diablo - Replace Bank Transformers	-	0.1	0.3	6.4	-	-	6.8
6986: Skagit Relicensing	-	-	-	-	4.7	6.1	10.8
6991: Skagit Licensing Mitigation	0.1	0.2	0.1	0.1	0.1	0.1	0.6

Table C.8
Power Supply CIP Detail (continued)

$ Millions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
A3: Cedar Falls - Tolt	**$1.8**	**$1.6**	**$1.3**	**$2.0**	**$2.3**	**$6.2**	**$15.2**
6324: Cedar Falls Powerhouse - Valvehouse Rehabilitation	-	-	-	-	-	0.6	0.6
6358: Cedar Falls Powerhouse - Penstock Stabilization	-	-	0.3	0.5	0.2	-	0.9
6406: Cedar Falls/South Fork Tolt - Minor Improvements Program	0.6	1.4	1.0	1.0	1.1	2.1	7.3
6450: Cedar Falls Powerhouse - Unit 5/6 Generator Protective Relay	0.4	0.1	-	-	-	-	0.5
6531: Cedar Falls - New Generator 5/6 Exciters	0.2	0.1	-	-	-	-	0.3
6534: Cedar Falls - Masonry Dam Stream Flow System Retrofit	0.1	0.0	-	-	-	-	0.2
6570: South Fork Tolt - DC Battery System & Charge Modernization	0.2	-	-	-	-	-	0.2
6572: Cedar Falls - DC Battery System and Charge Modernization	0.2	-	-	-	-	-	0.2
6573: Cedar Falls - Bank 6 Replacement	-	-	-	0.5	1.1	2.4	3.9
6574: Cedar Falls - Lines CF-CW & CF-RS Relay Protection Upgrade	-	-	-	-	-	0.6	0.6
6575: Cedar Falls - 6.6kV Switchgear Replacement	-	-	-	-	-	0.3	0.3
6576: Cedar Falls - 2 kV Switchyard Replacement	-	-	-	-	-	0.3	0.3
A4: Power Supply Other	**$3.4**	**$3.3**	**$3.0**	**$2.9**	**$2.9**	**$3.0**	**$18.4**
6102: Special Work Equipment - Generation Plant	0.8	0.9	0.9	0.9	1.3	1.3	6.0
6385: Power Production - Network Controls	0.8	0.7	0.2	0.0	0.0	(0.0)	1.6
6470: Generation Federal Reliability Standards Improvements	0.0	0.0	0.0	0.0	0.0	0.0	0.1
6530: Hydro Project Spill Containment	0.8	0.7	0.7	0.6	0.6	0.6	4.0
6600: SMT AutoLab	-	-	0.2	0.4	-	-	0.7
6990: Endangered Species Act Mitigation	1.0	1.0	1.0	1.0	1.0	1.0	6.0

Table C.9
Transmission CIP Detail

$ Millions	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Transmission	**$8.0**	**$12.6**	**$11.3**	**$10.1**	**$23.5**	**$20.2**	**$85.7**
B1: Transmission	**$8.0**	**$12.6**	**$11.3**	**$10.1**	**$23.5**	**$20.2**	**$85.7**
7011: Transmission Capacity	0.0	0.0	0.0	0.0	0.0	0.0	0.1
7104: Transmission Reliability	2.4	2.4	2.5	2.6	2.7	2.7	15.4
7105: Transmission Inter-Agency	0.5	0.5	0.5	0.5	0.5	0.5	3.1
7125: Denny Substation Transmission Lines	1.2	0.2	0.2	6.6	20.2	16.9	45.5
8461: Transmission Line Inductor Installation	3.2	6.3	5.6	0.3	-	-	15.4
8462: Transmission Line Reconductoring	0.6	3.1	2.4	-	-	-	6.2