Seattle City Light

2027-2032 Strategic Plan - Financial Forecast

EXECUTIVE SUMMARY

This document details the financial assumptions behind the rate path established by City Light's 2027-2032 Strategic Plan (the "Plan"). The proposed rate path provides the revenue required to deliver the strategic outcomes identified in the Plan.

Average rates are derived by dividing the revenue requirement by retail sales. City Light's revenue requirement is increasing around $165 million (10.5%) per year, and retail sales are growing by about 1% per year. There is a considerable amount of uncertainty in the out years. This forecast yields a rate path with increases of 9.5% in 2027 and 2028 and a range of annual increases between 7% to 11% in years 2029-2032.

RATE INCREASE SUMMARY

	2026[1]	2027	2028	2029	2030	2031	2032
Revenue Requirement, $M	$1,203	$1,319	$1,453	$1,595	$1,773	$1,973	$2,202
Annual Increase		9.6%	10.1%	9.8%	11.2%	11.2%	11.6%
Retail Sales GWh	8,989	8,998	9,050	9,074	9,212	9,356	9,538
Annual Change		0.1%	0.6%	0.3%	1.5%	1.6%	1.9%
Average Rate, ¢/kWh	13.4	14.7	16.1	17.6	19.3	21.1	23.1
Annual Increase		9.5%	9.5%	9.5%	9.5%	9.5%	9.5%
Rate Path Uncertainty[2]				+/-1.5%	+/-1.5%	+/-1.5%	+/-1.5%
Annual Increase (Rate Path)		**9.5%**	**9.5%**	**7%-11%**	**7%-11%**	**7%-11%**	**7%-11%**

[1] Planning values as of Apr 2026 that reflect current consumption profiles and retail rates (RSA surcharge is excluded).
[2]Increased uncertainty in out-year load and power cost timing may drive rate path higher or lower than Annual Increase shown above.

Below is a table of bill impacts of example customers.

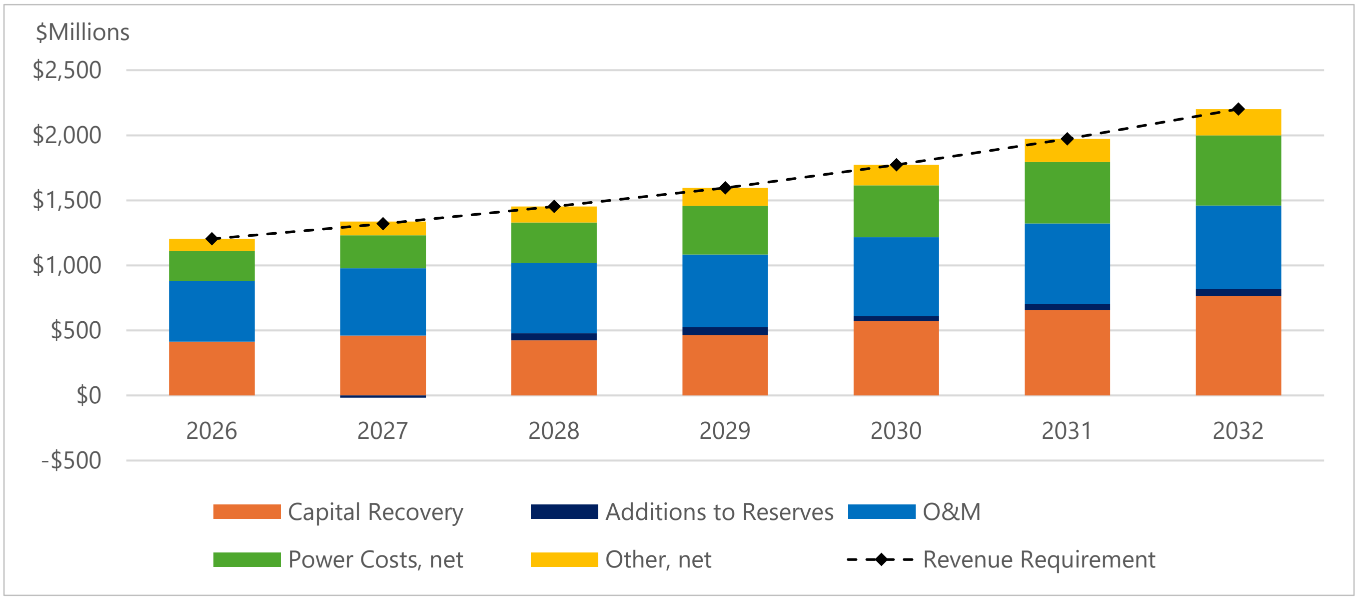
MONTHLY BILL IMPACTS

	Bill	Increase						
	2026	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**AVG**
Apartment - Electric Heat	$74	$7	$8	$8	$9	$10	$11	$9
Single Family Home - Electric Heat	$124	$12	$13	$14	$16	$17	$19	$15
UDP Single Family Home - Electric Heat	$50	$5	$5	$6	$6	$7	$7	$6
Small Commercial - Office	$173	$16	$18	$20	$22	$24	$26	$21
Medium Commercial - Grocery	$3,863	$367	$402	$440	$482	$528	$578	$466
Large Commercial - Hospital	$162,727	$15,459	$16,928	$18,536	$20,297	$22,225	$24,336	$19,630
Large Network - Data Center	$250,316	$23,780	$26,039	$28,513	$31,222	$34,188	$37,435	$30,196

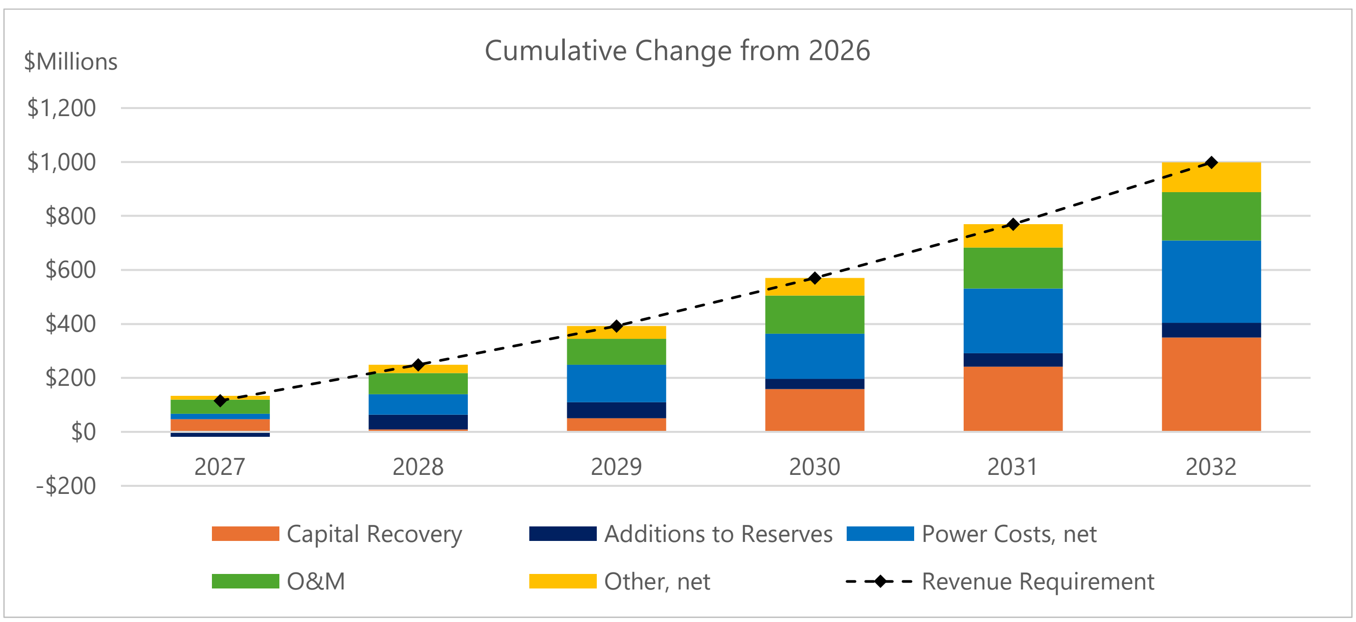
These bill impacts assume each customer has a bill increase of 9.5% and unchanged consumption. These impacts are examples only and will differ once the cost of service and rate design process is completed. Customers who decrease their consumption through energy efficiency measures will experience smaller bill impacts.

The charts and tables below summarize City Light's revenue requirements for 2027-2032.

REVENUE REQUIREMENT 2027-2032



REVENUE REQUIREMENT DRIVERS 2027-2032



RETAIL REVENUE REQUIREMENT SUMMARY

	2026	2027	2028	2029	2030	2031	2032
$, Millions							
Revenue Requirement	$1,203	$1,319	$1,453	$1,595	$1,773	$1,973	$2,202
Capital Recovery							
Debt Service	$249	$231	$255	$268	$276	$299	$326
Revenue Available for Capital & Liquidity[1]	$164	$212	$222	$256	$333	$404	$491
Operations & Maintenance (O&M)							
2026 O&M Baseline	$465	$465	$465	$465	$465	$465	$465
Inflation	$0	$18	$37	$56	$76	$95	$115
Existing hydro licensing (previously CIP)	$0	$11	$11	$12	$8	$9	$10
Change in REC costs from 2026	$0	-$1	-$2	-$7	-$13	-$15	-$16
New and expanded programs	$0	$24	$32	$35	$70	$64	$69
Net Power Costs							
New Resources	$9	$20	$25	$105	$106	$173	$241
Other Power and Wheeling Contracts	$295	$280	$330	$382	$398	$424	$443
Net Wholesale Revenue (NWR)	-$55	-$30	-$30	-$100	-$100	-$120	-$140
Power Related Revenues, Net	-$16	-$17	-$16	-$15	-$4	-$4	-$6
Other Revenues/Costs							
Taxes, Payments and Uncollectibles	$144	$156	$171	$188	$209	$231	$257
Miscellaneous Revenue	-$52	-$50	-$48	-$49	-$51	-$52	-$54

[1] Operating revenue available to cash fund the capital program or add to overall liquidity (cash reserves).

DRIVERS OF 2027-2032 REVENUE REQUIREMENTS AND RATES

1. Capital Recovery and additions to cash reserves
    - Capital requirements are expected to increase significantly, driven largely by replacement of underground infrastructure and implementation of the new Skagit License
    - 42% of 2027-2032 net capital requirements are expected to be funded with operating revenue
    - Debt service is expected to grow as the utility issues more debt
    - Around $240 Million additions to cash to support bond reserve and to meet 150 Days Cash on Hand metric

2. Operations and Maintenance (O&M)
    - Based on 2026 adopted O&M budget with inflation for the cost category expected to grow at approximately 4% per year
    - Reclassification of some existing hydro relicensing capitalized costs to O&M to follow accounting best practices (CIP reduced by the same amount)
    - New and expanded programs to support the strategic plan (see Appendix A for more details on new programs)

3. Net Power Costs
    - Bonneville (BPA) power and transmission costs are the largest single component at over $250 million; BPA power and transmission costs are expected to increase around 5% per year on average
    - New power resources are required to meet resource adequacy targets. Planning assumption is $239 million for roughly 276 aMW by 2032 for a combination of solar, wind, battery storage and transmission
    - NWR planning value is expected to gradually grow as the utility adds more renewable resources

4. Other Revenues/Costs[1]
    - Not a large driver, taxes grow proportionally with revenue

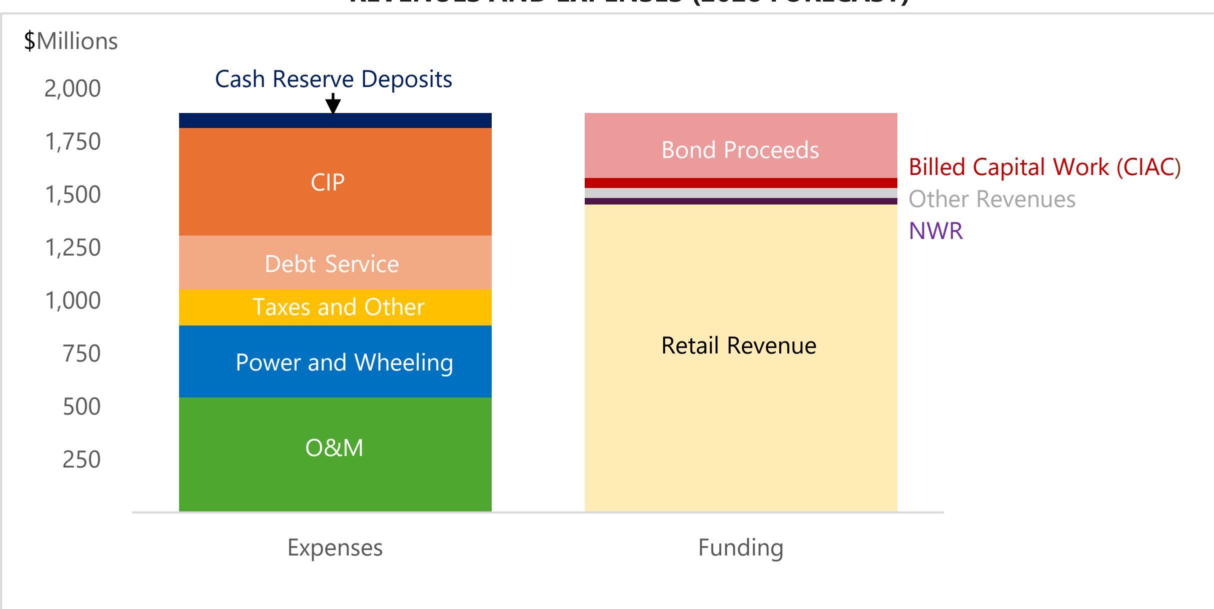
INTRODUCTION

The 2027–2032 Strategic Plan establishes key focus areas and defines specific outcomes for each. It also identifies and prioritizes the workstreams needed to achieve those outcomes. This document details the financial assumptions behind the Plan's outcomes and the associated 2027-2032 rate path to support it. The rate path is the annual change in the average retail rate for 2027-2032. Average retail rates are not actual billed rates but are the ratio of the revenue requirement to retail sales and represent the average impact on customer bills, assuming their consumption is constant.

$$average\ rate \left(\frac{\$}{kwh}\right) = \frac{revenue\ requirement\ (\$)}{retail\ sales\ (kwh)}$$

The revenue requirement is the amount of retail revenue needed to balance revenues with expenses and meet financial policies. The chart below illustrates how the revenue requirement is sized to meet expenses.

REVENUES AND EXPENSES (2028 FORECAST)



[1] *Includes city and state taxes, franchise payments and uncollectible revenue, which tend to grow in proportion to retail revenue. Miscellaneous revenue comes from a variety of fees and service charges, as well as investment interest earnings.*

The following is a short description of what is included in each primary component of the revenue requirement. These are discussed in detail in the subsequent sections of this document.

Capital Recovery

- Debt service payments needed to support the debt-financed portion of the current capital requirement.
- Per policy, retail revenue must be sized to achieve at least 1.80 times the annual debt service obligation.
- For this 6-year planning horizon, debt coverage is higher than 1.80x every year to meet the policy of revenue-funding greater than 40% of the 6-year CIP (See Appendix B).

O&M

- Cash-related expenses for all O&M costs excluding taxes, purchased power and transmission wheeling.
- Non-capitalized labor costs.
- Inflation assumptions, additional program funding requirements, as well as any mitigating cost reductions.

Power, Net

- Purchased power costs and wheeling costs, net of power revenues.
- Revenues from surplus power sales net of purchases, also called net wholesale revenue.
- Does not include costs of operating owned generation (e.g. Skagit, Boundary hydro projects), as these are part of O&M.

Other

- Includes tax payments, franchise payments and uncollectible revenue, net of miscellaneous revenues.

This document concludes with a short discussion of the retail sales forecast, which is the denominator in the average rate formula, see page 14.

CAPITAL RECOVERY (CIP AND BONDS)

Capital recovery reflects the cost of capital spending, as recovered over time. Net capital requirements are comprised of the capital improvement plan (CIP) less capital contributions, which are payments from outside sources that offset capital expenses.

Net Capital Requirements = CIP – Capital Contributions

Net capital requirements are not a direct component of the revenue requirement but, along with financial policies, determine the amount of debt (bonds) issued and the amount of net capital requirements funded with operating cash. The principal payments on outstanding debt and associated interest expense make up debt service.

Net capital requirements, along with financial policies, determine the amount of capital expenses funded by operating revenue and bond sales. City Light's current financial policies were established by Resolution 31187 and call for setting rates to yield sufficient revenue net of expenses to cover annual debt service obligations by 1.8 times and fund at least 40% of the capital programs with operating revenue over a six-year average. The revenue requirement forecast in this Plan meets both policy requirements.

The capital expense forecast is based on the 2026-2031 Adopted CIP plus additional investments to fund new initiatives related to demand response, reliability, new Skagit license, workforce and more. In addition, some CIP related to existing hydro licenses will be reclassified as O&M to follow best accounting practices. The baseline 2032 capital expense is extrapolated from 2030 and 2031. The CIP forecast used to set rates differs from the City's budget CIP. The budgeted CIP represents spending authority while the CIP forecast is reduced by 10% to reflect an assumption that only 90% of spending authority will actually be spent, and the forecast adjusts timing of spending to reflect projected cash outflows.

Table below summarizes capital requirements and funding sources. Capital contributions include third-party funding for capital expenses such as service connections and reimbursements for certain transportation projects and are included in the forecast as a credit to the total capital requirements. Capital funding from operations reflects cash drawdowns and may represent net operating proceeds from the current or previous year(s). Bond issuances during the 2027-2032 planning period total around $2.1 billion and will bring total outstanding debt to over $4.3 billion by 2032. The average funding for the 2027-2032 net capital requirements with operating proceeds is 42%, above the 40% target.[2]

CAPITAL REQUIREMENTS AND FUNDING

$, Millions	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Capital Requirements							
Adopted CIP	$460	$462	$452	$473	$471	$469	$514
Total Additions	$16	$31	$53	$93	$206	$325	$352
Existing Relicensing Cost Moved to O&M	-	-$10	-$10	-$11	-$7	-$7	-$8
New Skagit Relicensing Cost	$16	$2	$1	$6	$95	$87	$96
Strategic Initiatives	$0	$38	$62	$98	$119	$245	$264
Total CIP	$476	$493	$504	$566	$677	$794	$866
Capital Contributions	-$46	-$47	-$48	-$50	-$52	-$49	-$44
Total Net Capital Requirements	**$430**	**$446**	**$457**	**$516**	**$626**	**$744**	**$822**
Capital Funding							
Bond Proceeds	$181	$230	$304	$344	$358	$422	$421
Operations	$249	$216	$152	$172	$267	$323	$401
Total	**$430**	**$446**	**$457**	**$516**	**$626**	**$745**	**$822**
Total Debt Outstanding	$2,929	$3,056	$3,258	$3,499	$3,747	$4,048	$4,336

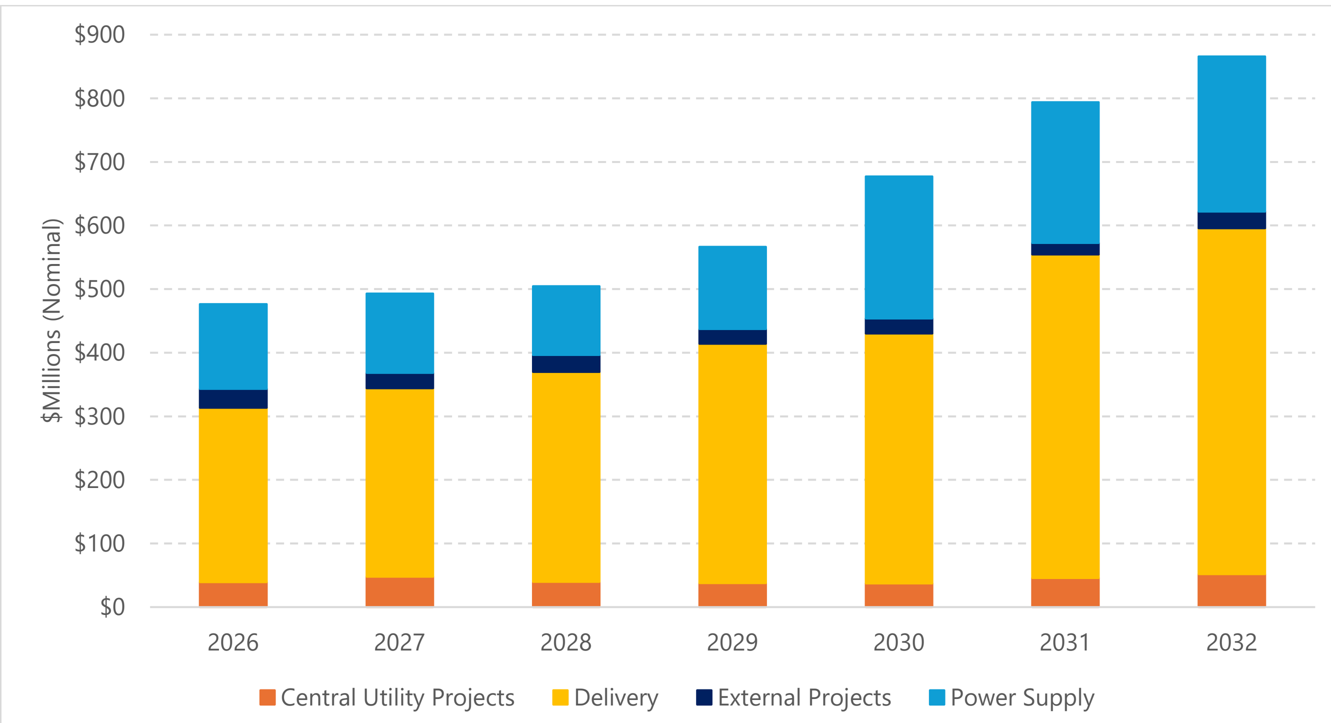
[2] *The average 2027-2032 capital funding from operations is calculated by taking the total 2027-2032 funding from operations ($1,531 million) and dividing by the total 2027-2032 Net Capital Requirements ($3,611 million) to get 42%.*

MAJOR CIP PROJECTS INCLUDED IN THE 2026-2031 ADOPTED CIP[1]

Master Project ID and Description	Six-year Total Spend, $M
8351: Overhead Equipment Replacements	$223.7
8366: Medium Overhead and Underground Services	$220.5
2250: Energy Efficiency	$196.6
8333: Distribution System Replacements	$167.6
8353: Underground Equipment Replacements	$141.8
8370: Network Services	$131.6
8630: Network Systems	$131.0
6987: Boundary Licensing Mitigation	$111.2
8452: Pole Attachments	$88.9
9969: Software Replacement Strategy	$79.7

[1] *Values reflect adjusted CIP after applying a 90% spending assumption.*

CAPITAL IMPROVEMENT PLAN[1]



[1] *Delivery includes programs on transmission and distribution.*

Capital requirements determine the size of future bond sales and resulting debt service, and the sales are timed to ensure sufficient liquidity to provide at least 150 days of operating cash on hand. The bond sale amounts shown below are slightly higher than bond proceeds shown above because the sales amounts include issue costs and required deposits into the bond reserve fund. All bond issues are assumed to have a 30-year term. For future bond sales 2027-2032, the forecast assumes an annual sale that closes in July with an interest rate of 5.0%, with the first repayment occurring the following year. Thus, the 2032 bond issue has no impact for this forecast term. To smooth the rate path, the forecast allows debt service coverage to fluctuate year-to-year so long as the six-year target of 40% or greater capital funding from operations is met.

BOND SALES AND DEBT SERVICE, $MILLION

	Bond Size	2027	2028	2029	2030	2031	2032
Existing[1]		$219	$228	$221	$207	$207	$206
2026 (Jul)	$187	$12	$12	$12	$12	$12	$12
2027 (Jul)	$237		$15	$15	$15	$15	$15
2028 (Jul)	$312			$20	$20	$20	$20
2029 (Jul)	$346				$22	$22	$22
2030 (Jul)	$361					$23	$23
2031 (Jul)	$425						$28
Total Debt Service		$231	$255	$268	$276	$299	$326
Debt Service Coverage		$521	$564	$619	$716	$822	$948
Debt Service Coverage Ratio		2.26	2.21	2.31	2.60	2.75	2.91

[1]*As of April 2026*

OPERATIONS AND MAINTENANCE (O&M)

Operations and maintenance expenses (O&M) are a large and diverse category of costs for day-to-day operations. It includes functions such as power production, distribution and transmission system operation and maintenance, customer services such as billing and meter reading, and administrative support. O&M as defined for this forecast does not include purchased power, wheeling and taxes; these are separate categories.

The basis for the 2027-2032 O&M forecast is the 2026 Adopted budget, which is then increased each year to reflect rising costs. The average annual cost increase is 3.8% per year, 1.2% higher than CPI inflation. The table below represents how O&M is projected to be spread across labor, benefits and other purposes; however, this is ultimately determined by the budget development process.

BUDGET O&M INFLATION BY CATEGORY

$, Millions	2026	2027	2028	2029	2030	2031	2032
Labor	$206	$215	$225	$235	$246	$257	$268
Labor Benefits	$102	$107	$111	$116	$120	$125	$129
Overhead Credit	-$61	-$64	-$66	-$69	-$72	-$75	-$78
Non-Labor	$153	$159	$165	$171	$176	$182	$188
Transfers to City	$90	$93	$95	$98	$100	$102	$104
Total Inflated O&M Budget	$490	$510	$530	$550	$570	$591	$612
Annual Change		$20	$20	$20	$20	$21	$21
Annual Change %		4.2%	3.9%	3.7%	3.7%	3.7%	3.6%

The following table details the adjustments made to the inflated O&M budget to yield the O&M forecast. In addition, funding for the new programs to deliver the outcomes of the Plan are added to the inflated budget (more information is included in Appendix A). The second part of the table outlines how the O&M forecast changes relative to the 2026 O&M Forecast.

O&M ADJUSTMENTS DETAIL

$, Millions	2026	2027	2028	2029	2030	2031	2032
Inflated 2026 Budget	$490	$510	$530	$550	$570	$591	$612
Adjustments							
add intertie moved from wheeling budget[1]	$1	$1	$1	$1	$1	$1	$1
add/subtract I937 RECs (change from 2026 levels)[2]	$1	-$1	-$2	-$7	-$13	-$15	-$16
subtract demand response incentives[3]	-$6	-$6	-$6	-$7	-$7	-$7	-$7
subtract engineering OH not included in budget[4]	-$6	-$6	-$6	-$7	-$7	-$7	-$8
subtract under-expenditure assumption[5]	-$15	-$15	-$16	-$17	-$17	-$18	-$18
add hydro relicensing costs[6]	$0	$11	$11	$12	$8	$9	$10
add new Skagit licensing costs[7]	$0	$0	$0	$0	$24	$18	$19
add new and expanded programs[8]	$0	$24	$32	$35	$46	$46	$50
Total O&M	$465	$517	$543	$561	$606	$617	$643
Adopted 2026 O&M Budget	$465	$465	$465	$465	$465	$465	$465
Changes from 2026							
Inflation	$0	$18	$37	$56	$76	$95	$115
Hydro licensing costs that were previously CIP	$0	$11	$11	$12	$8	$9	$10
Lower REC costs	$0	-$1	-$2	-$7	-$13	-$15	-$16
New/expanded programs (includes Skagit License)	$0	$24	$32	$35	$70	$64	$69
Total O&M	$465	$517	$543	$561	$606	$617	$643

[1] *Maintenance costs associated with ownership of the 3rd AC intertie. These wheeling costs are budgeted as purchased power but are categorized as O&M in financial statements.*
[2] *Renewable Energy Credits (RECs) purchases to meet state regulations are expected to decrease as more renewable energy is added to City Light's resource portfolio. These are differences from inflated Adopted 2026 levels.*
[3] *Demand response costs have been recategorized from O&M budget to Short-term Purchased Power Budget.*
[4] *Capitalized engineering overhead costs are not included in the budget but are applied to actual costs.*
[5] *Assumes 3% of O&M budget authority will remain unspent.*
[6] *Reflects a change in accounting practice that will result in certain Boundary and Skagit relicensing costs that are currently capitalized be categorized as O&M starting in 2027.*
[7] *Cost projections for the new Skagit license (see Appendix A for more detailed information).*
[8] *Cost projections for new and expanded programs identified in the strategic plan (see Appendix A for more detailed information).*

POWER COSTS, NET

This category includes all costs and revenue associated with wholesale power transactions. These include purchases and sales, wheeling (rented transmission) and ancillary services.

The forecast reflects key changes in the utility's resource portfolio: the expiration of the Columbia Basin Hydro contracts in 2026, the expiration of the Condon Wind contracts in 2028, and the decision to forgo election of the Priest Rapids Meaningful Priority option in 2027.

Additionally, the forecast incorporates new resource acquisitions needed to serve growing load, as outlined in the utility's Integrated Resource Plan. These additions are significantly more ambitious than those included in the 2025-2030 Strategic Plan. Resource acquisition plan continues to rely on a mix of utility-scale battery storage, wind generation, and solar generation. The cost of these new resources is also expected to be partially offset by selling surplus energy in the wholesale markets. The tables below summarize projections for net power costs.

LONG-TERM POWER AND WHEELING CONTRACTS

$, Millions	2026	2027	2028	2029	2030	2031	2032
BPA Power[1]	$174	$177	$204	$215	$227	$239	$249
BPA Wheeling[2]	$76	$79	$83	$123	$126	$139	$146
New Resources[3]	$9	$20	$25	$105	$106	$173	$241
Lucky Peak[4]	$11	$12	$12	$13	$13	$14	$14
Other Wheeling[5]	$5	$4	$5	$5	$5	$5	$5
Condon Wind[6]	$3	$3	$1	$0	$0	$0	$0
King County West Point[7]	$2	$2	$2	$2	$2	$3	$3
Priest Rapids[8]	$22	$2	$22	$23	$24	$24	$25
High Ross[9]	$0	$0	$1	$1	$1	$1	$1
Columbia Basin Hydro[10]	$2	$0	$0	$0	$0	$0	$0
Total LT Power & Wheeling Contracts	$304	$300	$355	$487	$504	$597	$684

[1] *Assumes BPA base power rates increase by 10% between 2026 and 2028 and 5% after 2028, and a product change from Block to Block/Slice starting in October 2028.*
[2] *Assumes BPA wheeling costs increase 3% annually on average and gradual growth in purchased transmission volumes.*
[3] *New resources identified by IRP totaling 276 aMW of nameplate capacity by 2032; these include solar and wind resources, transmission, and utility-scale battery storage.*
[4] *Reflects costs growing with inflation.*
[5] *Costs are expected to grow in line with contracted terms for each wheeling provider.*
[6] *Condon Wind contract ends in May 2028.*
[7] *KC West Point contract extends through March 2033.*
[8] *Priest Rapids projection assumes that costs for the Meaningful Priority product will escalate at 4 percent a year.*
[9] *High Ross contract requires only minimal O&M payments; all capital payments were completed in 2020.*
[10] *Columbia Basin Hydro contracts expire by the end of 2026.*

City Light's single largest power source is the Bonneville Power Administration (BPA). BPA power and wheeling bills are complex and based on many factors including City Light load, BPA base rates, BPA's load shaping charges and BPA's rate setting periods. City Light currently receives the Block product, which is fixed amount of energy every month. Starting in October 2028 City Light will start a new 20-year contract with BPA. City Light has elected a Slice/Block product, where the Slice Product is a "slice" of BPA's total output and will vary based on hydrological conditions.

BPA DETAIL

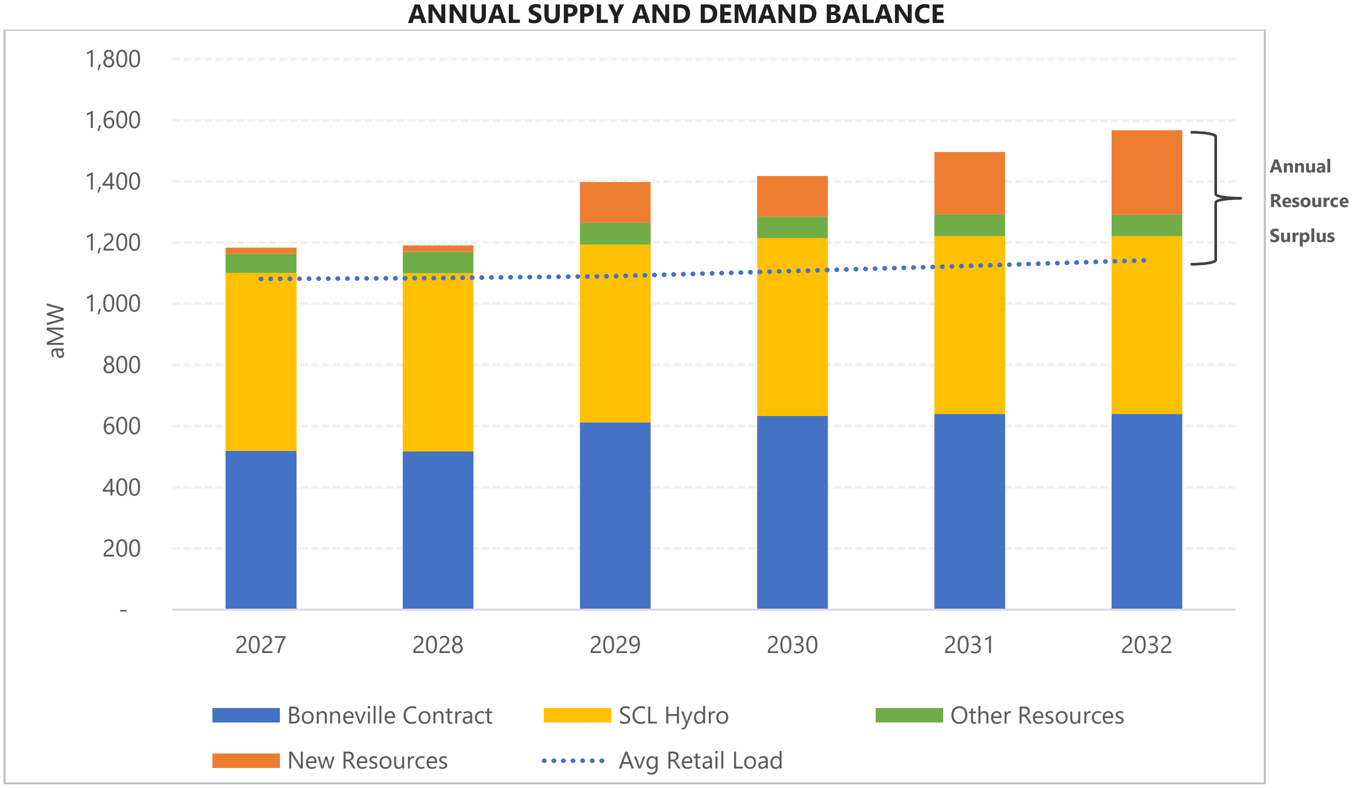
$, Millions	2026	2027	2028	2029	2030	2031	2032
Power Costs	$174	$177	$204	$215	$227	$239	$249
Transmission (Wheeling) Costs	$76	$79	$83	$123	$126	$139	$146
Total BPA Costs	$250	$256	$286	$338	$353	$378	$395
BPA Purchases, GWh[1]	4,377	4,544	4,579	4,761	4,770	4,788	4,783
BPA Transmission Purchases, MW	2,361	2,481	2,581	3,614	3,614	3,718	3,822

[1] *Starting on October 1, 2028 BPA purchases reflect an even BPA Block/Slice split, with Slice calculated using BPA's 1989-2018 10th-percentile historical water conditions.*

Long-term purchased power acquisitions will exceed retail load growth, on a volumetric basis. Because new wind and solar resources are intermittent, additional resources will be required to ensure that retail demand can be reliably met under varying conditions. Also, City Light's peak load is projected to increase faster than average load, further increasing firm resource needs to reliably meet load under stress conditions like extreme weather events.

The chart below shows City Light's annual resource mix and retail load. Production from owned hydro generation facilities varies significantly year-to-year with weather conditions. For planning purposes, this forecast of owned hydro generation is based on a 30th percentile of the past 25 years (2000-2025), and BPA Slice output is based on the 10th percentile. New power resource acquisitions are expected to increase the overall volume of surplus power available to be sold on the wholesale market. Net Wholesale Revenue is the revenue from selling surplus energy, net of purchases for load balancing.

ANNUAL SUPPLY AND DEMAND BALANCE



The planning values for Net Wholesale Revenues, Net—defined as wholesale power revenues minus wholesale power sales—are summarized in the table below. These revenues are projected to grow as new resources come online, resulting in a surplus of wholesale power. The dip in 2027 and 2028 values reflects a change in assumptions since the last plan; the 2026 amount had assumed that a significant volume of new resource capacity would be online by then. In this forecast, large additions are delayed and are now expected in the 2029 timeframe.

Given evolving markets and climate change, there is considerable uncertainty around these planning values. Variations in wholesale revenues are mitigated by the Rate Stabilization Account (RSA), a cash reserve and rate mechanism designed to insulate customers from short-term wholesale market and weather risk. Any differences between actual and planning values will be transferred to/from the RSA (SMC 21.49.086).

WHOLESALE REVENUES, NET

$, Millions	2026	2027	2028	2029	2030	2031	2032
Wholesale Revenues, Net	$55	$30	$30	$100	$100	$120	$140

Power related revenues are comprised of long-term power sales, net revenues from sales of ancillary market services, and transmission sales. The following table details these assumptions.

POWER RELATED REVENUES, NET

$, Millions	2026	2027	2028	2029	2030	2031	2032
Power Contracts							
Delivery to Pend Oreille County[1]	$4	$4	$4	$5	$0	$0	$0
Priest Rapids	$5	$5	$6	$6	$0	$0	$0
BPA Credit for South Fork Tolt[2]	$3	$3	$2	$0	$0	$0	$0
Power Marketing, Net[3]	$5	$4	$4	$4	$4	$4	$4
Transmission Sales[4]	$0	$0	$0	$0	$0	$0	$0
Total Power Related Revenues, net	$16	$17	$16	$15	$4	$4	$4

[1] *Current agreement ends in 2029.*
[2] *Current contract expires in 2028.*
[3] *Power marketing revenues (net of purchases) are earned from sales of ancillary services such as reserve capacity sales, which are supported by flexibility and excess capacity inherent in City Light's generation and transmission assets.*
[4] *Short-term transmission sales. Includes resale of BPA point-to-point transmission and 3rd AC transmission capacity.*

OTHER COSTS AND MISCELLANEOUS REVENUES

This "other" category is made up of costs and revenues such as taxes, interest income and fees for retail services.

OTHER COSTS (TAXES, PAYMENTS AND UNCOLLECTIBLES) DETAIL

$, Millions	2026	2027	2028	2029	2030	2031	2032
City Taxes[1]	$73	$79	$87	$95	$106	$117	$131
State Taxes[2]	$51	$55	$61	$67	$74	$82	$90
Franchise Payments and Other Taxes[3]	$11	$11	$13	$14	$15	$17	$19
Uncollectible Revenues[4]	$9	$10	$11	$12	$13	$15	$17

[1] *City taxes, which are 6% of retail revenues, plus some other revenues.*
[2] *State taxes are 3.8734% of retail revenues, plus some other revenues and contributions.*
[3] *City Light negotiates franchise agreements with incorporated cities and unincorporated communities within its service territory.*
[4] *Uncollectible revenue is assumed to be 0.75% of retail revenues.*

MISCELLANEOUS REVENUE SOURCES DETAIL

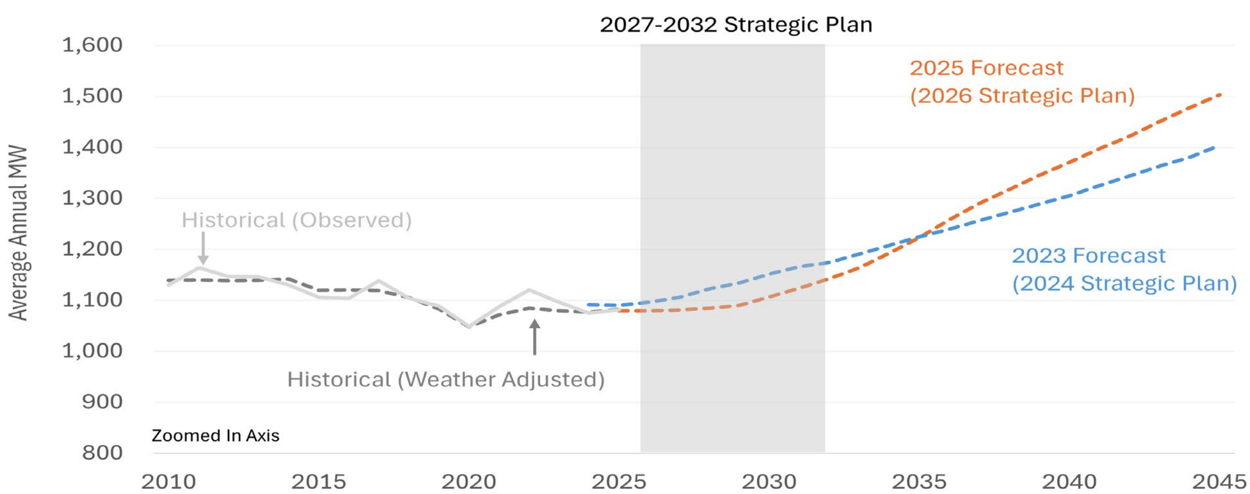
$, Millions	2026	2027	2028	2029	2030	2031	2032
Non-Base Rate Retail Revenue[1]	$7	$7	$7	$7	$7	$7	$8
Other Revenue[2]	$22	$22	$22	$23	$23	$24	$24
Suburban Undergrounding[3]	$2	$2	$2	$2	$2	$3	$3
Property Sales[4]	$1	$1	$1	$1	$1	$1	$2
Interest Income[5]	$19	$18	$15	$16	$17	$17	$18
Operating Fees & Grants	$0	$0	$0	$0	$0	$0	$0
Net RSA Transfers[6]	$(1)	$0	$0	$0	$0	$0	$0
Total Other Revenue Sources	$50	$50	$47	$49	$50	$52	$55

[1] Non-base rate retail revenue includes revenues from retail customers for services or programs which are not dictated by the revenue requirement. Examples include elective green power programs, distribution capacity charges and power factor charges.
[2] Other revenue includes a broad range of income sources, such as late payment fees, payments for damages to property, transmission tower attachments, distribution pole attachments and account change fees. These revenues are forecasted using the averages of the past two to three years and are expected to grow with inflations.
[3] Suburban undergrounding revenues are collected from customers in certain suburban cities for the repayment of discretionary municipal undergrounding of parts of their distribution system.
[4] Property sales based on historical averages. No large sales are assumed in this forecast.
[5] Interest income assumes City Cash Pool cash holdings accrue interest at an annual rate of 2.0-2.5%.
[6] RSA surcharge revenue less RSA deposits. During Q1 2026 there was an RSA surcharge in place, this small amount shown is RSA surcharge revenue retained to pay the associated utility taxes.

RETAIL SALES

The forecast of retail sales is based on City Light's 2025 official load forecast, which predicts load growth of 6.1% from 2026 to 2032. Energy efficiency is expected to continue to reduce sales, outpacing new load from economic growth. This reflects investment undertaken by customers as well as utility incentives. However, electric vehicles and heat pump conversions are expected to fuel material load growth during the strategic planning period. The amount and timing of this new electrification load is very uncertain and will continue to be studied. The chart below shows slightly slower near-term retail load growth compared to the previous strategic plan.

RETAIL LOAD FORECAST: LONG TERM

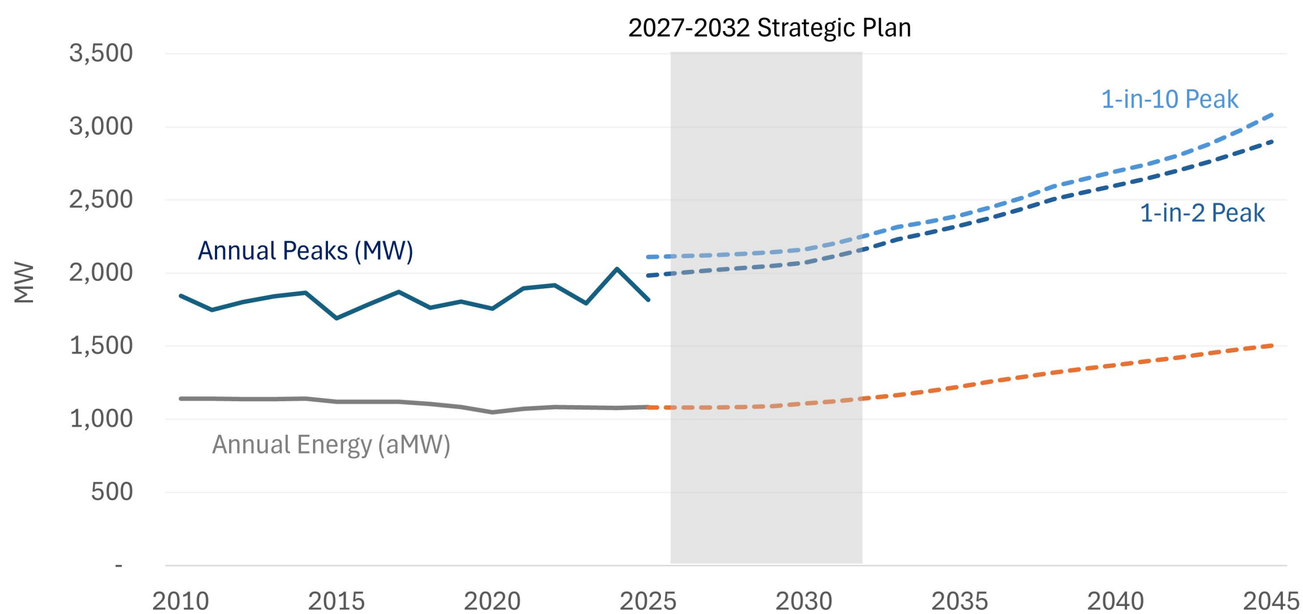


RETAIL SALES FORECAST BY CUSTOMER CLASS: 2026-2032

GWh	2026	2027	2028	2029	2030	2031	2032
Residential	3,278	3,300	3,333	3,330	3,362	3,385	3,424
Small and Medium	3,422	3,416	3,429	3,453	3,526	3,608	3,702
Large and High Demand	2,289	2,282	2,288	2,290	2,324	2,362	2,411
Total	**8,989**	**8,998**	**9,050**	**9,074**	**9,212**	**9,356**	**9,538**
Annual change							
Residential		0.7%	1.0%	-0.1%	0.9%	0.7%	1.1%
Small and Medium		-0.2%	0.4%	0.7%	2.1%	2.3%	2.6%
Large and High Demand		-0.3%	0.2%	0.1%	1.5%	1.7%	2.1%
Total		**0.1%**	**0.6%**	**0.3%**	**1.5%**	**1.6%**	**1.9%**

Rising demand for electric vehicle charging and heating will push coincident peak demand to rise even more than average energy consumption, driving a need for greater energy delivery capacity in transmission and distribution lines. Given long planning and construction timelines, capacity expansions need to be in place well before peak load growth arrives. Utility revenue is primarily recovered through per-KWh energy sales so higher capacity needs add more cost pressure that is contributing to driving up retail rates. The chart below shows the growth in peak load (P50 = 50th percentile, P90 = 90th percentile and P100 = 100th percentile or max load).

RETAIL SALES PEAK VS. ENERGY FORECAST: LONG TERM



APPENDIX A: NEW AND EXPANDED PROGRAMS

As part of developing the Strategic Plan, City Light identified the critical investments required to achieve prioritized strategic outcomes. To balance service levels with affordability, multiple rounds of prioritization were conducted to right-size these investments, ensuring that only the most essential spending was advanced.

The table below outlines incremental spending additions above inflation adjustments for operations and maintenance (O&M) and the capital improvement program (CIP). A detailed description of investments for each category follows.

INCREMENTAL STRATEGIC PLAN INVESTMENTS

	O&M						CIP					
$ Millions	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Customer Experience	$0.3	$0.3	$0.3	$0.3	$3.3	$4.4	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Power Supply	$7.9	$10.5	$13.2	$23.7	$18.0	$18.1	$13.3	$12.2	$12.2	$23.2	$25.1	$27.8
Reliability	$3.8	$5.4	$5.4	$5.9	$6.0	$7.8	$23.0	$46.2	$82.4	$92.3	$202.8	$213.8
Sustainability	$2.1	$3.1	$3.1	$3.1	$4.1	$4.2	$0.3	$0.0	$0.0	$0.0	$9.7	$10.2
Technology	$8.0	$10.6	$10.9	$11.2	$11.6	$11.9	$0.0	$0.0	$0.0	$0.0	$4.5	$9.0
Workforce	$1.8	$1.8	$1.8	$1.8	$3.5	$3.6	$1.8	$3.2	$3.2	$3.2	$3.2	$3.2
New Skagit License	$0.0	$0.0	$0.0	$24.4	$17.5	$19.4	$2.1	$1.0	$6.4	$94.7	$86.9	$96.1
Total	**$23.9**	**$31.7**	**$34.7**	**$70.4**	**$64.0**	**$69.4**	**$40.4**	**$62.6**	**$104.0**	**$213.3**	**$332.2**	**$360.0**

CUSTOMER EXPERIENCE

Adds a dedicated expert to support enhancing data collection and research methods, ensuring real-time understanding of ratepayer needs. This will also establish a formal Community Partner Network that will deepen collaboration with community-based organizations, enabling ongoing, two-way engagement that informs program design and delivery. Expanded coordination with City departments and partner agencies will further improve outreach to vulnerable populations and highly impacted communities, ensuring services are accessible, equitable, and responsive.

POWER SUPPLY

Acquiring Generation and Transmission Resources

Investments in staffing, advanced planning tools, and specialized expertise will position the utility to meet growing energy demand and increasing system complexity. Expanded capabilities in resource planning, market participation, and policy development will support the acquisition of new generation resources, particularly renewable energy and optimize participation in regional energy markets. Modernized modeling and analytics will improve forecasting and risk management, ensure reliable and cost-effective power supply while supporting the transition to a cleaner energy portfolio.

Customer Energy Resources

Investments in programs, staffing, and enabling technologies will expand customer participation in energy efficiency, demand response, and customer-owned renewable generation. Additional staff and improved systems will support program delivery, customer engagement, and faster integration of distributed energy resources. These efforts will help customers reduce and shift energy use, lower system costs, and contribute to grid reliability.

By integrating customer-side resources into system planning, the utility can reduce the need for large-scale infrastructure investments while building a more flexible and resilient energy system.

Transmission Access

Enhanced staffing, consulting expertise, and system investments will modernize transmission policies, processes, and tools to improve access and utilization. Updated contracts, pricing structures, and operational protocols will support transparent and equitable access to transmission capacity. Improved systems for scheduling, tracking, and billing transmission use will increase efficiency and enable broader participation in wholesale markets. These investments will maximize the value of existing infrastructure, generate new revenue opportunities, and enhance overall grid reliability without requiring significant new construction.

RELIABILITY

Asset Data Management

Investments in asset data and work management practices, including additional specialized staff and modernized systems, will enable a more proactive and standardized approach to managing utility infrastructure. Expanding internal expertise will support implementation of best practices in asset lifecycle management, improve data quality, and enhance coordination across workgroups. These improvements will lead to more informed capital planning, reduced emergency repairs, and lower long-term costs for ratepayers.

Physical Asset Security

Targeted investments in both staffing and infrastructure will strengthen the utility’s ability to prevent, detect, and respond to evolving physical security threats. Dedicated security personnel will provide continuous monitoring and rapid response capabilities, while upgrades to surveillance, access controls, and site hardening at critical facilities will improve system resilience. Together, these efforts reduce operational risk and help ensure uninterrupted delivery of essential services.

Fleet Management

Increased investment in fleet renewal and supporting staff capacity will improve the reliability and availability of vehicles and equipment essential to utility operations. Replacing aging vehicles with modern, lower-emission alternatives will reduce maintenance demands and downtime, enabling field crews to complete work more efficiently. These investments also advance environmental objectives by lowering greenhouse gas emissions and improving air quality in the communities served.

Strengthen Distribution System

Enhanced capital and staffing investments will accelerate the replacement and modernization of critical transmission and distribution infrastructure. Additional engineering, project management, and field resources will support the design and delivery of system upgrades, including advanced protection, control, and automation technologies. Expanded programs to replace aging underground cables and other high-risk assets will improve system performance, reduce outage frequency and duration, and enhance overall grid resilience.

Generation Facilities

Focused investments and technical staffing in generation facilities will address aging infrastructure, reduce operational risks, and improve long-term asset performance. Engineering, construction, and maintenance resources will support critical upgrades, including structural reinforcements, seismic improvements, and enhanced debris management systems. These efforts will help ensure continued reliable and efficient energy production while minimizing unplanned outages and maintenance costs.

Wildfire Risk Reduction and Vegetation Management
Expanded funding and staffing for wildfire mitigation and vegetation management will strengthen the utility's ability to proactively manage this important risk. Additional arborists, field crews, and program support staff will enable increased inspection cycles, hazard tree removal, and compliance with regulatory requirements. These investments will reduce the likelihood of wildfire-related outages, protect public safety, and preserve system reliability.

SUSTAINABILITY

Vehicle Electrification
Investments in staffing and infrastructure will accelerate the deployment of a public electric vehicle charging network. Dedicated personnel will support planning, design, and construction of charging sites, ensuring timely delivery and effective integration with the electric grid. Expanding access to reliable, affordable charging infrastructure will support transportation electrification, reduce emissions, and improve equitable access for customers without home charging options.

Reduce Energy Burden
Additional staffing and system enhancements will strengthen the delivery of customer assistance programs designed to keep energy costs affordable. Investments in modernized application and processing systems, combined with permanent program staff, will improve efficiency, reduce wait times, and ensure consistent access to benefits. These efforts help stabilize household energy costs and support broader economic resilience within the community.

Building Electrification
Expanded technical staffing across multiple teams will provide customers with the expertise needed to transition to electric technologies in homes and businesses. Engineers, planners, and customer advisors will assist with system capacity assessments, equipment selection, and service upgrade planning. These investments will enable more efficient electrification, reduce emissions, and help customers make cost-effective energy decisions.

TECHNOLOGY

Significant investments in technology systems and skilled personnel will modernize core utility operations and enhance service delivery. Expanded cybersecurity staffing and tools will strengthen protection of critical infrastructure and reduce enterprise risk. Additional IT professionals across key functional areas - including data management, system implementation, and geographic information systems - will restore and sustain essential institutional capabilities.

Investments in customer-facing platforms will improve accessibility, allowing customers to manage accounts, request services, and engage with the utility through flexible, digital channels. At the same time, modernization of grid management, asset management, and power supply systems will improve operational visibility, enable advanced analytics, and support faster, more informed decision-making. Together, these investments create a more resilient, efficient, and customer-responsive utility.

WORKFORCE

Strategic investments in workforce planning, staffing, and training will ensure the utility is equipped to meet current and future service demands. Additional resources will support comprehensive evaluation of job roles, compensation structures, and career pathways to remain competitive in attracting and retaining talent.

Expanded training programs and dedicated instructional staff will strengthen technical skills development, improve safety outcomes, and accelerate workforce readiness. Increased staffing and program support will also enhance workplace safety initiatives, including broader participation in safety-sensitive programs.

Investments in facilities and maintenance staff will shift operations from reactive repairs to proactive asset stewardship, addressing deferred maintenance and improving the reliability of critical infrastructure. Collectively, these efforts will build a skilled, resilient workforce capable of delivering safe, reliable, and cost-effective service to customers.

SKAGIT RELICENSING

The Skagit Relicensing Project has reached a milestone with a Comprehensive Settlement Agreement being finalized during Q1 and Q2 of 2026. This comprehensive settlement agreement sets forth a unified strategy for overseeing the Skagit watershed, including restoring salmon habitat, protecting tribal cultural resources, managing flood risk in downstream communities, enhancing public recreation, and continuing to deliver reliable, carbon-free energy for decades to come. This settlement will become part of the City’s formal license application to the Federal Energy Regulatory Commission (FERC) for a new 50-year license to operate the Skagit Project.

APPENDIX B: RATE SETTING TARGETS AND GUIDELINES

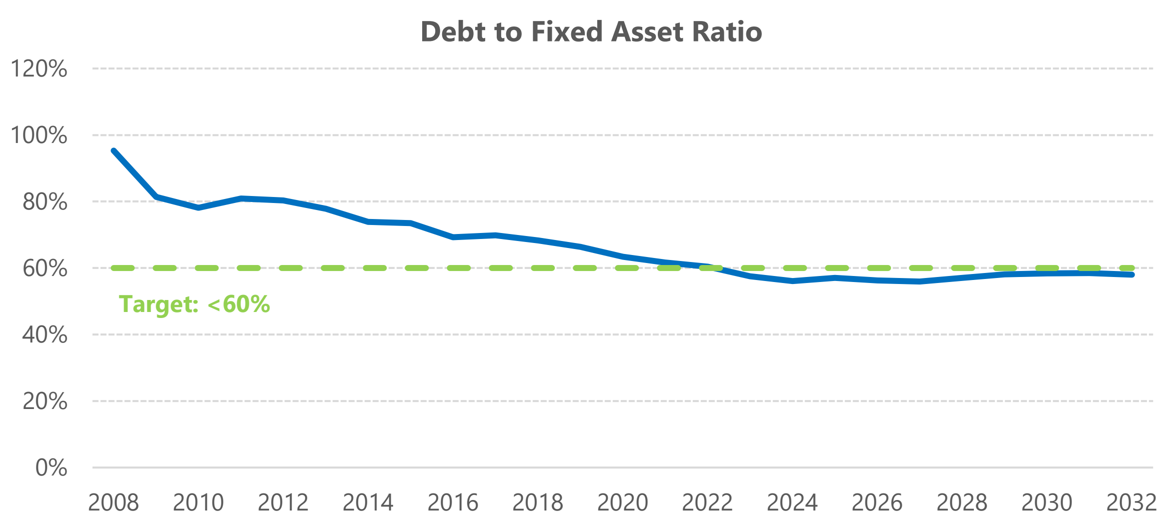
Council-Adopted Financial Policies, established in 2010 by Resolution 31187

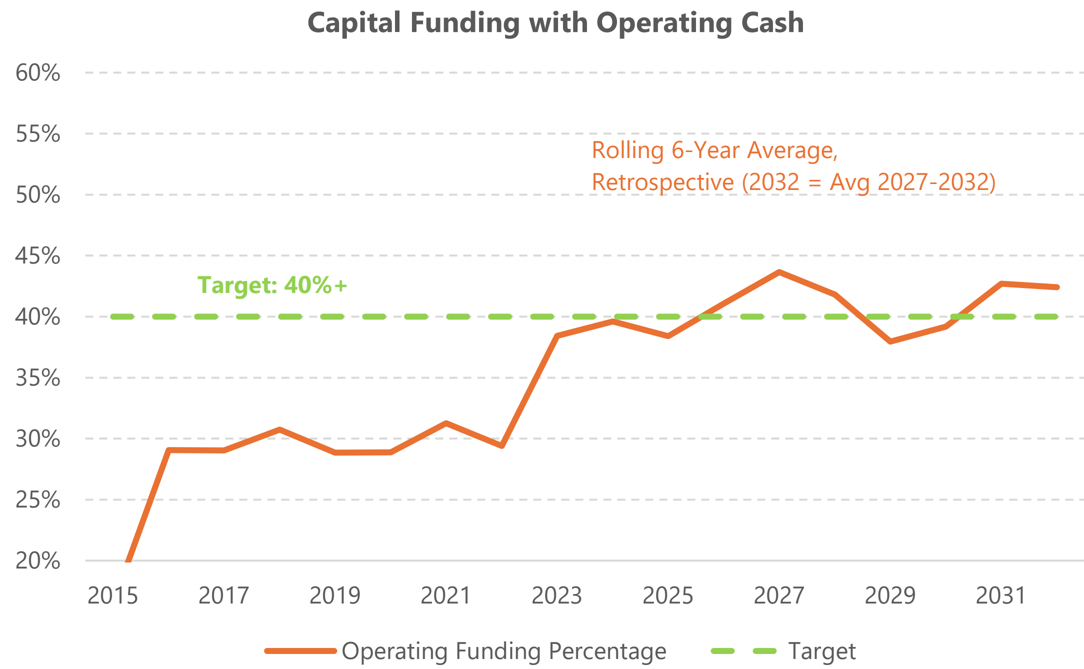
1. Rate Setting Guideline: It is the policy of the City of Seattle to set electric rates for the City Light Department at levels sufficient for it to achieve a debt service coverage ratio of 1.8x.
2. Debt Policy: The City Light Department will manage its capital improvement program so that on average over any given six-year capital improvement program it will fund 40% of the expenditures with cash from operations.

Supplemental Targets and Guidelines, approved by City Light Review Panel in 2024

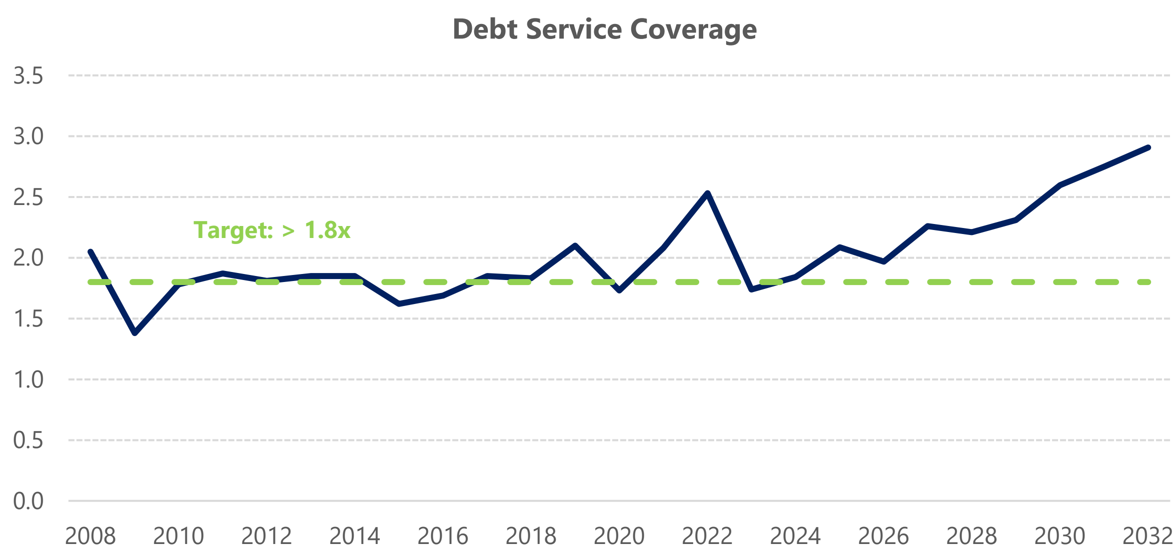
1. Assurance to cover debt payments: At least 1.80x debt service coverage in any given year, and a 6-year rolling average greater than 1.90x.
2. Target for funding of the capital plan: Six-year average operating cash funding of net capital requirements greater than 40%.
3. Debt leverage target: Debt-to-fixed asset ratio less than 60%.
4. Liquidity target: Days cash on hand greater than 150 days.

The charts below show the history and forecast of financial metrics. The revenue requirements and associated rate path outlined in this report meet all the financial targets.

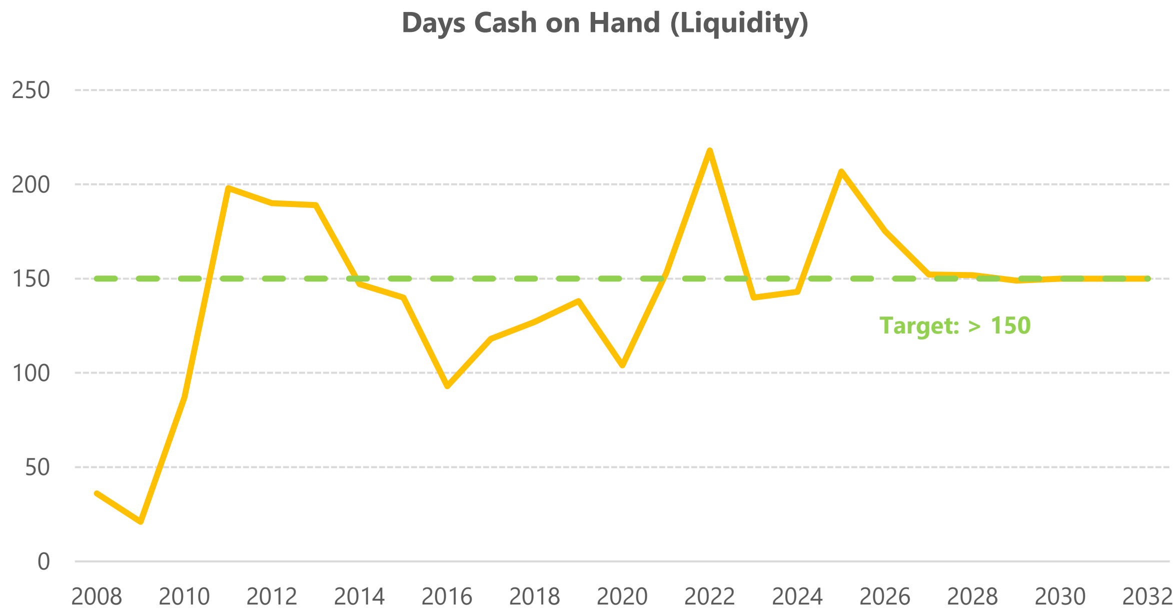




Capital Funding with Operating Cash
60%
55%
50%
45%
40%
35%
30%
25%
20%
Rolling 6-Year Average,
Retrospective (2032 = Avg 2027-2032)
Target: 40%+
2015
2017
2019
2021
2023
2025
2027
2029
2031
Operating Funding Percentage
Target



Debt Service Coverage
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
Target: > 1.8x
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032



METRIC CALCULATIONS

Debt Service Coverage = (Operating Revenues – Operating Expenses + Cash Adjustments + City Taxes*)/ Debt Service

Debt-to-Fixed Asset Ratio = Long-Term Debt / (Plant in Service net of Accumulated Depreciation + Construction Work in Progress)

Capital Funding from Operations = 6 Year Operating Funding / (6 Year CIP – 6 Year Contributions)

Days Cash on Hand = (Operating Account + RSA) / ((Operating Expenses – Depreciation and Amortization**) / 365)

** Because City Light is part of the City of Seattle, taxes paid to the City of Seattle are considered junior lien to debt service and are not included in the taxes category for the purposes of calculating debt service coverage.*

*** Also includes amortization (non-cash) amounts in operating expenses (i.e., hydro relicensing, energy efficiency)*

APPENDIX C: DOCUMENTATION FOR THE RATE STABILIZATION ACCOUNT

2027 and 2028 Planning Values for the RSA

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2027													
Total Net Variable Power Costs ($000's)	$19,000	$19,000	$17,000	$23,000	$20,000	$22,000	$24,000	$34,000	$19,000	$19,000	$15,000	$21,000	$252,000
Total Retail Sales (MWh)	915	808	804	703	671	634	692	696	651	713	797	914	8,998
Net Variable Power Price ($/MWh)													**$28**
2028													
Total Net Variable Power Costs ($000's)	$26,000	$28,000	$23,000	$23,000	$19,000	$17,000	$17,000	$27,000	$28,000	$23,000	$35,000	$45,000	$311,000
Total Retail Sales (MWh)	918	842	807	705	673	635	692	696	651	714	800	918	9,051
Net Variable Power Price ($/MWh)													**$34**

Net Variable Costs - Strategic Plan 2027

Power Cost Adjustment Input	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Variable Power Costs (net)													
Long-term Power Contracts	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$18,057*	*$216,684*
Wheeling	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$6,944*	*$83,323*
Other Power and Transmission Revenue	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$1,378*	*-$16,538*
NWR	*-$4,989*	*-$4,394*	*-$6,337*	*-$436*	*-$3,278*	*-$1,153*	*$762*	*$10,445*	*-$4,721*	*-$4,434*	*-$9,016*	*-$2,450*	*-$30,000*
Net Variable Power Costs ($000's)	$19,000	$19,000	$17,000	$23,000	$20,000	$22,000	$24,000	$34,000	$19,000	$19,000	$15,000	$21,000	$252,000
Total Retail Sales (GWh)	915	808	804	703	671	634	692	696	651	713	797	914	8,998
Net Variable Power Price ($/MWh)													**$28**

Net Variable Power Costs - 2027 details

LT Power & Wheeling	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$18,057	$216,684
BPA Power	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$14,782	$177,379
Priest Rapids	$157	$157	$157	$157	$157	$157	$157	$157	$157	$157	$157	$157	$1,881
Condon Wind	$237	$237	$237	$237	$237	$237	$237	$237	$237	$237	$237	$237	$2,840
Lucky Peak	$963	$963	$963	$963	$963	$963	$963	$963	$963	$963	$963	$963	$11,552
New Resources	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$1,686	$20,227
King County West Point	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$193	$2,314
High Ross	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$41	$492
Wheeling	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$6,944	$83,323
BPA Wheeling	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$6,569	$78,830
Other Wheeling	$374	$374	$374	$374	$374	$374	$374	$374	$374	$374	$374	$374	$4,493
Power & Wheeling ($000's)	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$25,001**	**$300,007**

Power & Transmission Revenues	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Delivery to Pend Oreille County	$351	$351	$351	$351	$351	$351	$351	$351	$351	$351	$351	$351	$4,212
Priest Rapids	$445	$445	$445	$445	$445	$445	$445	$445	$445	$445	$445	$445	$5,342
BPA Credit for South Fork Tolt	$219	$219	$219	$219	$219	$219	$219	$219	$219	$219	$219	$219	$2,627
Power Marketing Net	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$4,358
Transmission Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Power Revenues, net ($000's)	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$1,378**	**$16,538**

Net Wholesale Revenue	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Planned Net Revenue ($000's)	$4,989	$4,394	$6,337	$436	$3,278	$1,153	-$762	-$10,445	$4,721	$4,434	$9,016	$2,450	$30,000

Retail Power Sales	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Customer Sales (GWh)	915	808	804	703	671	634	692	696	651	713	797	914	8,998

Net Variable Costs - Strategic Plan 2028

Power Cost Adjustment Input	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Variable Power Costs (net)													
Long-term Power Contracts	$25,908	$26,282	$24,012	$17,979	$15,836	$12,316	$11,088	$12,200	$26,273	$21,463	$33,916	$39,911	$267,185
Wheeling	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$87,315
Other Power and Transmission Revenue	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$1,326	-$15,910
NWR	-$6,120	-$4,504	-$7,029	-$888	-$2,933	-$1,189	-$482	$8,477	-$4,313	-$4,787	-$4,907	-$1,325	-$30,000
Net Variable Power Costs ($000's)	$26,000	$28,000	$23,000	$23,000	$19,000	$17,000	$17,000	$27,000	$28,000	$23,000	$35,000	$45,000	$311,000
Total Retail Sales (GWh)	918	842	807	705	673	635	692	696	651	714	800	918	9,051
Net Variable Power Price ($/MWh)													**$34**

Net Variable Power Costs - 2028 details

LT Power & Wheeling	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Power	$25,908	$26,282	$24,012	$17,979	$15,836	$12,316	$11,088	$12,200	$26,273	$21,463	$33,916	$39,911	$267,185
BPA Power	$20,848	$21,210	$18,663	$12,310	$9,892	$6,656	$5,511	$6,738	$21,060	$16,592	$29,116	$35,108	$203,704
Priest Rapids	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$1,859	$22,311
Condon Wind	$257	$241	$325	$243	$292	$0	$0	$0	$0	$0	$0	$0	$1,357
Lucky Peak	$629	$657	$850	$1,253	$1,478	$1,485	$1,404	$1,288	$1,039	$697	$626	$629	$12,035
New Resources	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$2,075	$24,898
King County West Point	$198	$198	$198	$198	$198	$198	$198	$198	$198	$198	$198	$198	$2,371
High Ross	$42	$42	$42	$42	$42	$42	$42	$42	$42	$42	$42	$42	$509
Wheeling	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$7,276	$87,315
BPA Wheeling	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$6,887	$82,643
Other Wheeling	$389	$389	$389	$389	$389	$389	$389	$389	$389	$389	$389	$389	$4,673
Power & Wheeling ($000's)	**$40,461**	**$40,835**	**$38,565**	**$32,532**	**$30,388**	**$26,868**	**$25,641**	**$26,753**	**$40,826**	**$36,016**	**$48,469**	**$54,464**	**$354,501**

Power & Transmission Revenues	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Delivery to Pend Oreille County	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$372	$4,465
Priest Rapids	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$463	$5,556
BPA Credit for South Fork Tolt	$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$128	$1,532
Power Marketing Net	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$363	$4,358
Transmission Sales	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Power Revenues, net ($000's)	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$1,326**	**$15,910**

Net Wholesale Revenue	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Planned Net Revenue ($000's)	$6,120	$4,504	$7,029	$888	$2,933	$1,189	$482	-$8,477	$4,313	$4,787	$4,907	$1,325	$30,000

Retail Power Sales	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Customer Sales (GWh)	918	842	807	705	673	635	692	696	651	714	800	918	9,051