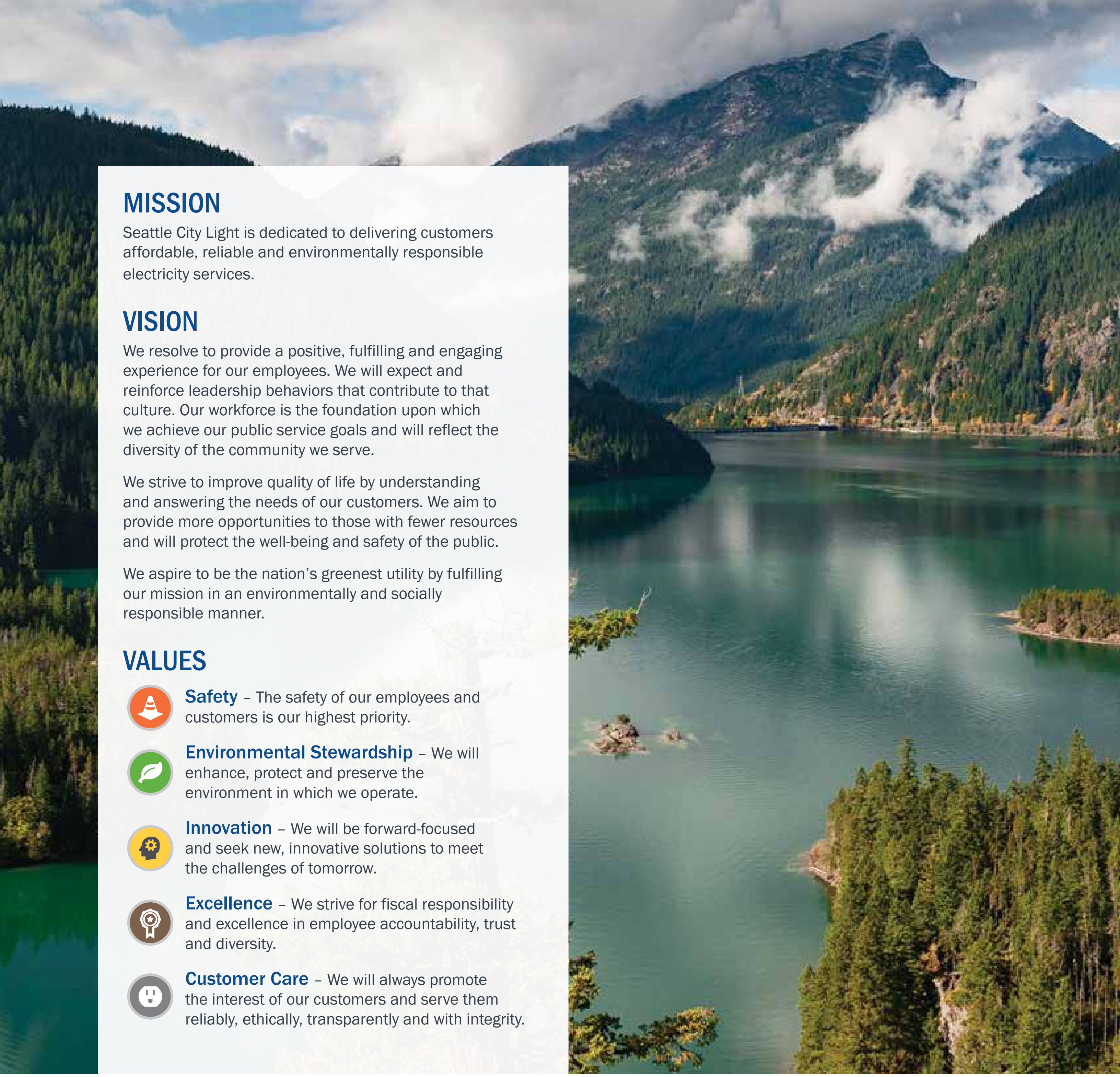
2018 ANNUAL REPORT Seattle City Light

ON SOLID GROUND



MISSION

Seattle City Light is dedicated to delivering customers affordable, reliable and environmentally responsible electricity services.

VISION

We resolve to provide a positive, fulfilling and engaging experience for our employees. We will expect and reinforce leadership behaviors that contribute to that culture. Our workforce is the foundation upon which we achieve our public service goals and will reflect the diversity of the community we serve.

We strive to improve quality of life by understanding and answering the needs of our customers. We aim to provide more opportunities to those with fewer resources and will protect the well-being and safety of the public.

We aspire to be the nation's greenest utility by fulfilling our mission in an environmentally and socially responsible manner.

VALUES

Safety – The safety of our employees and customers is our highest priority.

Environmental Stewardship – We will enhance, protect and preserve the environment in which we operate.

Innovation – We will be forward-focused and seek new, innovative solutions to meet the challenges of tomorrow.

Excellence – We strive for fiscal responsibility and excellence in employee accountability, trust and diversity.

Customer Care – We will always promote the interest of our customers and serve them reliably, ethically, transparently and with integrity.

Seattle City Light

A STRONG FOUNDATION FOR AN EVOLVING FUTURE

Change is integral to the human condition. When we encounter new experiences and new challenges, we rely on our core values to transform and adapt, reinventing ourselves in the process. A public utility is no different. As customer expectations evolve and new technologies change what's possible, utilities must adapt and transform while staying true to their mission. For Seattle City Light, thriving amid change requires a firm foundation and new levels of agility and innovation.

When I joined City Light in October, I recognized the strides City Light had made in preparing for the future and wanted to ensure that momentum would continue. This year, City Light built on its solid foundation by charting a course forward with a new strategic plan, significant additions to our core infrastructure and a utility-wide goal to exceed the expectations of our customer-owners. It was a year of meaningful progress for City Light.

With the support of our stakeholders and community partners, we completed the 2019-2024 Strategic Plan, which identified four priority areas for the utility: customer service, affordability, clean energy and continuing progress on our core business. The priority areas include specific and measurable goals and initiatives. Progress will improve our utility and bring value to our customer-owners. The 2019-2024 Strategic Plan is a living document that has become a cornerstone for how City Light operates. Its utility-wide goals cascade to individual employee goals which help us all understand how we contribute to the success of City Light.

One project of which we are especially proud is the Denny Substation. In 2018, Denny was officially energized and is now online. It is supporting customers' high voltage transmission operations as we prepare to connect it with our distribution system, supporting customers in the global innovation center of South Lake Union and beyond. With its public amenities and beautiful art installations, this unique facility has reinvented the concept of a substation from a utilitarian structure into a true community space. We look forward to sharing that space in mid-2019.

Change is inevitable and constant. Although utility industry practices have been relatively fixed for many years, we are at the precipice of great change. City Light is committed to meeting the future head-on and delivering on the value proposition that is the basis of public power. Our overarching goal is to help our customers meet their energy needs in whatever way they choose. They are, and always will be, the reason we exist.

This annual report presents the 2018 accomplishments that are shaping City Light's future and our transformation as a utility. As we move forward into 2019, I'm excited for the future and I believe we can and will be a regional and national leader. It's an honor to lead City Light's talented and dedicated staff in bringing value to our customer-owners.

Sincerely,

Debra Smith
General Manager and CEO

WE POWER SEATTLE

In 2018, City Light completed the 2019-2024 Strategic Plan which establishes a path forward for making informed decisions to meet the current and future needs of the utility and its customers. Building on the utility's legacy of bold, visionary action, the Strategic Plan candidly addresses the challenges and operational priorities that will enable our adaptive, resilient organization to look forward to a powerful future.

The City Light Executive Team led the utility's planning effort with input from customers, the City Light Review Panel, City of Seattle leaders, community members, business leaders, employees and other key stakeholders. Their combined guidance provided direction on how the utility will best position itself to flourish in this changing industry into the next decade. The City Light Review Panel, along with representatives from the City Budget Office and City Council staff, met regularly to hear from City Light leaders about the plan and provided valuable insight that helped shape this effort. We want to thank the members of the Review Panel and those who made the 2019-2024 Strategic Plan possible.

Six-Year Rate Path

Even though the Seattle area is growing rapidly, electricity consumption is not following suit. Downward-trending electricity consumption represents a tremendous victory for Seattle's energy conservation efforts. The 2019-2024 Strategic Plan calls for rate increases to produce enough revenue to cover rising costs while responding to customers' declining electricity use. The plan proposes a six-year rate path that increases 4.5% annually on average for 2019-2024. Decreasing retail sales account for about one-third of the 2019 rate increase, and 1% of the 4.5% six-year average.

ANNUAL INCREASE

2019	5.8%
2020	5.4%
2021	3.6%
2022	3.9%
2023	4.0%
2024	4.2%
	AVERAGE 4.5%

Since the City Council approved City Light's first Strategic Plan in 2012, the utility has continued to ensure its customers receive the highest possible level of service. This strategic planning process included five stages.

1. Develop a Strategic Framework
January–December 2017
- Developed priorities and strategic objectives.
- Forecasted costs and rates.
- Shared proposed initiatives with the Review Panel and Executive Team.

2. Conduct Stakeholder Outreach
September 2017–April 2018
- Spearheaded an extensive market research survey and meetings with stakeholders.

3. Strategy Development
December 2017–March 2018
- Refined initiatives based on outreach and financial baseline.

4. Shared Draft Plan and Sought Input
March 2018
- Identified core themes: customer service, affordability, clean energy and continuing progress on our core business.

The Four Priorities

Through the strategic initiatives laid out in the 2019-2024 Strategic Plan, City Light is developing a comprehensive response to the challenges facing the utility. The plan identifies four strategic priorities: customer service, affordability, clean energy and continuing progress on our core business. The first three priorities are areas of strategic focus where City Light must make changes to respond to industry challenges. As we drive for change, we will not lose sight of our values and mission, which is why City Light's fourth priority is to continue to maintain and improve our core business.

PRIORITY 1: CUSTOMER SERVICE

Upgrade customer service practices to meet evolving customer needs and expectations.

- Modernize Customer Service

PRIORITY 2: AFFORDABILITY

Keep customers' bills affordable and stable by implementing strategies to control costs, capture new revenues and restructure rates.

- Business Process Improvement
- Revenue Recovery and Rates
- Managing the Cost of Growth
- Evolving Energy Market

PRIORITY 3: CLEAN ENERGY

Deliver robust and innovative programs to promote the efficient use of clean energy and protect the shared ecosystem.

- Environmental Stewardship
- Clean, Renewable-Powered City

PRIORITY 4: CONTINUING PROGRESS ON OUR CORE BUSINESS

Invest in our infrastructure and workforce to provide a consistent level of service, reliability and response.

5. Mayoral and City Council Approval

May–June 2018

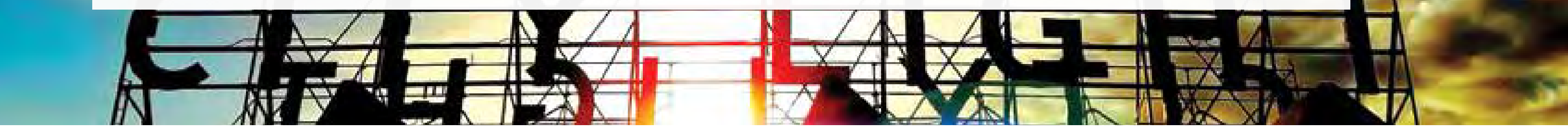
- Delivered the 2019-2024 Strategic Plan to the Office of the Mayor.
- Worked with the Review Panel as they continued to review and provide input on the Strategic Plan.

6. The Next Steps

- The Strategic Planning team will continue to provide progress reports, including milestone achievements and performance targets, to the City Light Review Panel and City Light Executive Team quarterly.
- Guided by City Light General Manager and CEO Debra Smith, the process to update the Strategic Plan will begin in the second quarter of 2019.
- The Strategic Planning team will continue to amend and adjust the current plan with an anticipated delivery of the 2021–2026 Strategic Plan to the Office of the Mayor by May 2020.

SERVING OUR CUSTOMER-OWNERS

Delivering customers affordable, reliable and environmentally responsible electricity services is essential to the success of our utility. As the industry continues to shift and innovate, it's imperative for City Light to augment a customer-centric culture, enhance the customer experience and provide value to our customers by meeting their energy needs in whatever way they choose. This year, City Light continued to improve its customer service to enhance the overall customer experience for residential and industrial customers alike.

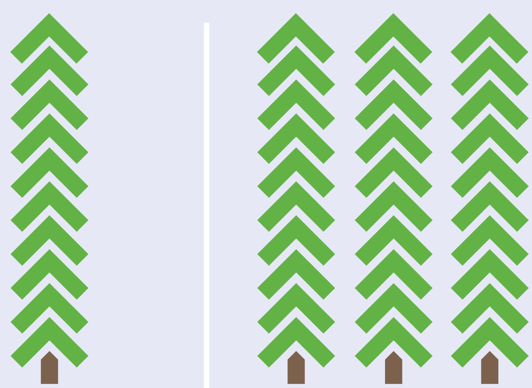


Utility Discount Program

City Light's Utility Discount Program (UDP) is one of the most substantial income-qualified assistance programs in the country, with a 60% discount on electric bills. City Light continues its efforts to assist customers who have difficulty paying their bills by increasing enrollment in this program. As of 2018, nearly 32,000 customers have enrolled in UDP.

Planting Trees Throughout Our Service Area

In 2018, Seattle City Light planted:



100

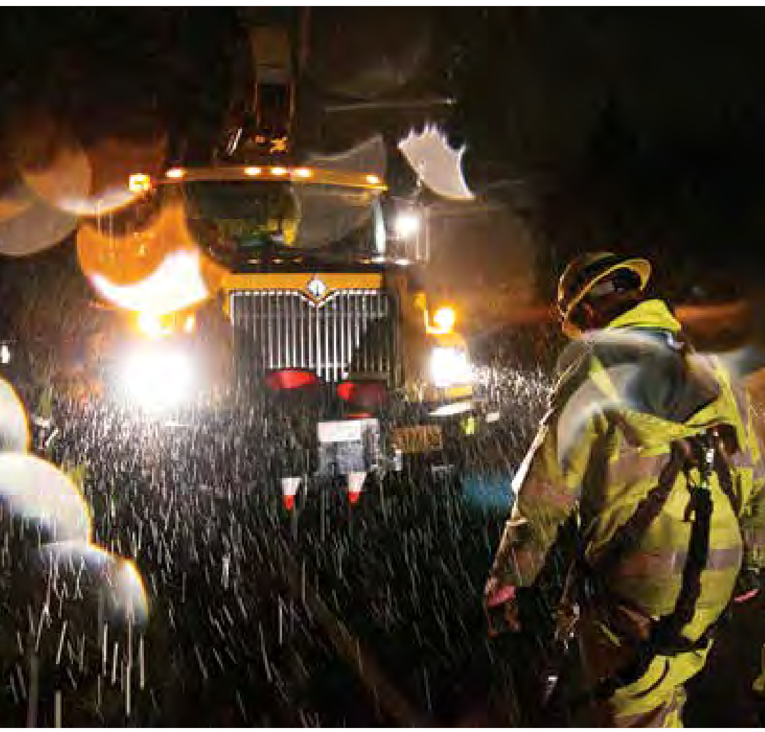
Street trees in collaboration with SDOT and community volunteers

300

Small trees funded by City Light in collaboration with the Trees for Neighborhood program

City Light in Our Community

City Light's community outreach efforts promote utility programs and strategic initiatives, help mitigate project and construction-related issues and share the stories and corporate citizenship activities of the utility. City Light's Community Outreach team oversees the communication efforts for system improvement work and 50-75 capital improvement projects each year. These projects represent nearly $500 million in utility improvement and infrastructure work annually. As a utility, City Light continues to find new and creative ways to engage with customers, stakeholders and the public, with a focus on racial and social equity.



Addressing Our Customers' Needs

In early 2018, City Light addressed a large number of backlog issues initiated by customers or identified directly by the utility. Customer Care team members worked together to resolve these issues, including refunds, moves, billing corrections and adjustments. By the end of Q1, City Light reduced the total backlog by 99%. This was made possible thanks to the work of dedicated employees and strategic decision-making which prioritized issues impacting lower-income customers. While some immediate utility customer service issues have been successfully resolved, new processes, plans, partnerships and technologies are being implemented to avoid any future recurrence of similar challenges. City Light is committed to delivering a positive customer experience along with accurate and timely bills.

Rolling Out Advanced Meters

City Light continued the rollout of its advanced meters that communicate wirelessly to utility systems. The advanced meters provide accurate meter reading and reduce operating costs along with the utility's environmental footprint. After beginning in 2014, this large-scale implementation project is now in its final stages. As of December 2018, a total of 409,054 new meters were exchanged, and mass deployment will be completed in 2019, improving the overall experience for City Light's customers.

PROTECTING OUR ENVIRONMENT

City Light is committed to serve as stewards of the environment by enhancing, protecting and preserving the natural spaces in which it operates. Not only has the utility remained carbon neutral since 2005, City Light has continued to protect and restore crucial habitats for the vulnerable species in our region. With the effects of climate change becoming more present each day, the utility values environmental stewardship more than ever.

Revitalizing Stossel Creek

The innovative Stossel Creek Pilot Project will replant portions of logged land now owned by City Light to grow a new forest that aims to be more resilient to climate change. City Light and its partners, including Mountains to Sound Greenway Trust, Seattle Public Utilities and the Northwest Natural Resource Group, received a $140,000 grant to reforest land around Stossel Creek in the Tolt River watershed northeast of Carnation. The grant money is being provided by the Wildlife Conservation Society through its Climate Adaptation Fund, a program supported and established by a grant from the Doris Duke Charitable Foundation. City Light and its partners implemented the first phase of the project in 2018 and look forward to continuing the project in 2019 and beyond.

City Light Partners with Skagit Land Trust

City Light, in partnership with the Skagit Land Trust, received a $1.6 million grant to purchase at least 100 acres in the Skagit River watershed, protecting high-quality fish habitats. The project area includes the Skagit, Sauk and Cascade Rivers and their major tributaries, including certain creeks upstream of Sedro-Woolley. The rivers are used by Chinook salmon and steelhead, both of which are listed as threatened with extinction under the federal Endangered Species Act.

Mill Pond and Sullivan Creek Habitat Restoration

The restoration of native fish in tributaries to the Boundary Dam reservoir is a major focus of City Light's Boundary License. Sullivan Creek is the largest of the tributaries that feeds into the Pend Oreille River and Boundary Dam reservoir. The most significant native fish habitat restoration project was the removal of Mill Pond Dam. The dam was removed in late 2017. In spring 2018, the high flows removed the remaining sediment. Gravel and wood transported downstream will create new pools and spawning beds for native fish.

When spring flows receded, the former Mill Pond site was sculpted into a complex multithread channel system, including side-channel habitat and off-channel wetland areas. Over 80 engineered log jams were installed throughout the nearly three-mile reconstructed channel and floodplain to create protected pools that provide refuge for fish, creating gravel beds for spawning and storing nutrients. The utility planted thousands of trees, shrubs and grasses that were grown from native seeds collected at the project site more than three years ago. The team also completed the construction of a new 2.5-mile loop trail system within the project area.

Promoting Environmental Equity

City Light's Environmental Equity Program at the North Cascades Environmental Learning Center continued to grow in 2018. The program started in 2017, in partnership with the local chapter of Latino Outdoors. In 2018, City Light brought 20 young adults from the Seattle Latino community to learn about environmental careers and experience the wilderness of the North Cascades. In addition, the National Park Conservation Association sponsored a Diablo Lake boat tour for about 60 participants, including members from three other environmental equity affinity groups; Outdoor Afro, Asian Outdoors and InterIM Program WILD. Boat tour participants learned about the history of the Skagit River Valley, the production of electricity from City Light's hydroelectric projects and job opportunities.

CONSTRUCTING TOMORROW

The growing skyline is one of many bellwethers for the rapid change the Seattle area is experiencing. As the region evolves, so have the expectations of our customers. With new electrical delivery innovations becoming more accessible, City Light continues to anticipate, embrace and appreciate change. These changes have tasked our utility to become more nimble while preparing for the next advancement on the horizon.

Enhancing Grid Performance and Cybersecurity

The threat of cyberattack looms larger than ever. Attackers are becoming more sophisticated and the list of potential targets is growing. As the utility's technological footprint moves beyond substations, powerhouses and control centers, the threat is expanding to distribution areas. Today, the security of business and home assets such as advanced meters are being considered by utilities. External nation-states are targeting the energy sector and investing resources in techniques with specific capabilities against utility technologies.

City Light is continuously working to determine and implement appropriate cybersecurity controls for its grid assets and systems. This includes subjecting to and complying with an extensive set of international cybersecurity standards intended to increase the security and reliability of the electric power grid.

Denny Substation

City Light made significant strides toward the completion of its first substation in more than 30 years. This year, the Denny Substation was officially energized and brought online. Construction continues on the new Denny Network that will help distribute power across Seattle's urban core. In 2019, City Light looks forward to hosting a celebration event to commemorate the public opening of the substation and its community amenities.

Miller Community Center Microgrid Project

In 2018, City Light issued a request for proposals for a solar microgrid project at Miller Community Center. The project is designed to serve as a resilient community resource in the event of an emergency. It will include the installation of a battery energy storage system, roof-mounted solar panels and microgrid controls. The microgrid will provide backup power for the community center during emergency events, such as a windstorm or unplanned power outage. The project is slated to complete final design in late 2019, with construction to be completed in the first half of 2020. The project is partly funded by a grant from the Washington State Department of Commerce Clean Energy Fund.

City Light-Seattle Fire Vault Fire Partnership

On June 18, Seattle Fire Chief Harold Scoggins and City Light Interim General Manager and CEO Jim Baggs reached an agreement to solidify the partnership of the Vault Response Team, a 48-member team trained to safely address the public safety needs resulting from network vault fire incidents. City Light provides specialized supplies and equipment to treat these fires along with updated intel on City Light's network maps. This innovative partnership, which takes a proactive approach, is a major advancement in the industry.

EV Charging Station in Beacon Hill

On January 30, Mayor Jenny Durkan and City Light unveiled the first city-owned DC fast-charging stations for electric vehicles within the service area. The two stations, located in Beacon Hill, are a part of a city-wide plan to install DC fast-charging stations throughout City Light's service territory. City Light has plans to install additional charging stations over the next two years and has engaged with communities across its service territory to seek input on future charging sites.

TABLE OF CONTENTS

AUDITED FINANCIAL STATEMENTS

SUPPLEMENTARY INFORMATION (Unaudited)

INDEPENDENT AUDITORS' REPORT

To the Housing, Health, Energy and Workers' Rights Committee
The City of Seattle – City Light Department
Seattle, Washington

Report on the Financial Statements

We have audited the accompanying financial statements of The City of Seattle – City Light Department (the "Department"), an enterprise fund of The City of Seattle, Washington, as of and for the years ended December 31, 2018 and 2017, and the related notes to the financial statements, as listed in the table of contents.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America and the standards applicable to financial audits contained in *Government Auditing Standards* issued by the Comptroller General of the United States. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal controls relevant to the Department's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Department's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Department as of December 31, 2018 and 2017, and the respective changes in financial position and cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

As discussed in Note 1, the financial statements present only the Department and do not purport to, and do not present fairly the financial position of The City of Seattle, Washington, as of December 31, 2018 and 2017 and the respective changes in financial position and cash flows thereof for the years then ended in accordance with accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

As discussed in Note 1, the Department adopted the provisions of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, effective January 1, 2018. The cumulative effect of the change is shown in the current year. Our opinion is not modified with respect to this matter.

Other Matters

Required Supplementary Information

Accounting principles generally accepted in the United States of America require that the required supplementary information as listed in the table of contents be presented to supplement the financial statements. Such information, although not a part of the financial statements, is required by the Governmental Accounting Standards Board who considers it to be an essential part of financial reporting for placing the financial statements in an appropriate operational, economic, or historical context. We have applied certain limited procedures to the required supplementary information in accordance with auditing standards generally accepted in the United States of America, which consisted of inquiries of management about the methods of preparing the information and comparing the information for consistency with management's responses to our inquiries, the financial statements, and other knowledge we obtained during our audit of the financial statements. We do not express an opinion or provide any assurance on the information because the limited procedures do not provide us with sufficient evidence to express an opinion or provide any assurance.

Other Information

Our audit was conducted for the purpose of forming an opinion on the financial statements as a whole. The other information as listed in the table of contents, which is the responsibility of management, is presented for purposes of additional analysis and is not a required part of the financial statements. Such information has not been subjected to the auditing procedures applied in the audit of the financial statements, and accordingly, we express no opinion or provide any assurance on it.

Other Reporting Required by Government Auditing Standards

In accordance with *Government Auditing Standards*, we have also issued a report on our consideration of the Department’s internal control over financial reporting and on our tests of its compliance with certain provisions of laws, regulations, contracts, and grant agreements and other matters. The purpose of that report is to describe the scope of our testing of internal control over financial reporting and compliance and the results of that testing, and not to provide an opinion on the internal control over financial reporting or on compliance. That report is an integral part of an audit performed in accordance with *Government Auditing Standards* in considering the Department’s internal control over financial reporting and compliance.

Baker Tilly Virchow Krause, LLP

Madison, Wisconsin
May 16, 2019

The following discussion and analysis of the financial performance of The City of Seattle—City Light Department (the Department) provides a summary of the financial activities for the years ended December 31, 2018, and 2017. This discussion and analysis should be read in combination with the Department's financial statements, which immediately follow this section.

ORGANIZATION

The Department is the public electric utility of The City of Seattle (the City). As an enterprise fund of the City, the Department owns and operates generating, transmission, and distribution facilities and delivers electricity to approximately 461,500 customers in Seattle and certain surrounding communities. The Department also provides electrical energy to other City agencies at rates prescribed by City ordinances.

OVERVIEW OF THE FINANCIAL STATEMENTS

The Department's accounting records are maintained in accordance with generally accepted accounting principles for proprietary funds as prescribed by the Governmental Accounting Standards Board (GASB). The Department's accounting records also follow the Uniform System of Accounts for Public Licensees prescribed by the Federal Energy Regulatory Commission (FERC).

This discussion and analysis is intended to serve as an introduction to the Department's financial statements, which are comprised of the financial statements and the notes to the financial statements and include the following:

Balance Sheets, Statements of Revenues, Expenses, and Changes in Net Position, and Statements of Cash Flows—The financial statements provide an indication of the Department's financial health. The balance sheets include all the Department's assets, deferred outflows of resources, liabilities, deferred inflows of resources, and net position using the accrual basis of accounting, as well as an indication about which assets can be utilized for general purposes, and which assets are restricted due to bond covenants and other commitments. The statements of revenues, expenses, and changes in net position report all the revenues and expenses during the time periods indicated. The statements of cash flows report the cash provided and used by operating activities, as well as other cash sources, such as investment income and cash payments for bond principal and capital additions and betterments.

Notes to the Financial Statements—The notes to the financial statements provide additional information that is essential to a full understanding of the data provided in the financial statements.

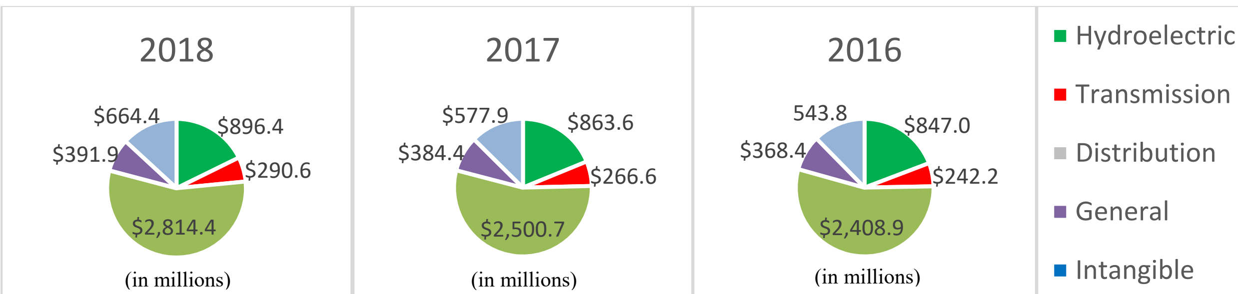
CONDENSED BALANCE SHEETS

($ in millions)	December 31 2018	2017	2016
Assets:			
Utility plant—net	$ 3,820.8	$ 3,509.5	$ 3,214.7
Restricted assets	263.7	252.4	222.0
Current assets	374.0	343.6	286.5
Other assets	432.0	416.8	396.2
Total assets	4,890.5	4,522.3	4,119.4
Total deferred outflows of resources	57.9	83.2	94.9
Total assets and deferred outflows of resources	$ 4,948.4	$ 4,605.5	$ 4,214.3
Liabilities:			
Long-term debt	$ 2,564.9	$ 2,417.4	$ 2,165.3
Noncurrent liabilities	365.8	409.6	433.6
Current liabilities	316.6	280.7	266.5
Other liabilities	37.8	36.3	37.2
Total liabilities	3,285.1	3,144.0	2,902.6
Total deferred inflows of resources	163.9	123.6	94.2
Net position:			
Net investment in capital assets	1,523.8	1,382.8	1,310.5
Restricted:			
Rate stabilization account	25.0	25.0	25.0
Total restricted	25.0	25.0	25.0
Unrestricted—net	(49.4)	(69.9)	(118.0)
Total net position	1,499.4	1,337.9	1,217.5
Total liabilities, deferred inflows, and net position	$ 4,948.4	$ 4,605.5	$ 4,214.3

ASSETS

Utility Plant—Net

2018 Compared to 2017 Utility plant assets net of accumulated depreciation and amortization increased $311.3 million to $3,820.8 million in 2018. Utility plant assets were comprised of hydroelectric production plant, $896.4 million, which increased $32.8 million, transmission plant, $290.6 million, which increased $24.0 million, distribution plant, $2,814.4 million, which increased $313.7 million, general plant, $391.9 million, which increased $7.5 million, and intangible assets, $664.4 million which increased $86.5 million. The net increase in utility plant assets were partially offset by a $70.4 million net increase in Accumulated depreciation and amortization to $1,893.8 million.



The $313.7 million increase in distribution plant is primarily due to Denny substation, $133.0 million, seawall replacement, $39.7 million, equipment replacement, $27.3 million. An increase of $86.5 million in Intangibles is primarily due to PeopleSoft 9.2 reimplementation, $24.7 million, Advanced Metering system and AM system integration, $11.7 million, Customer Information system, $5.8 million, Enterprise Document Management system and WAMS Document Repository, $5.7 million, and Automated Utility Design, $5.2 million. The $32.8 million increase in Hydro assets is primarily due to Diablo U31 rebuild. The $24.0 million increase in Transmission is primarily due to seawall replacement, equipment replacement, and Boundary bank 156 transformer replacement.

Other components of utility plant include Construction work-in-progress, $486.2 million, which decreased $103.1 million, nonoperating property, $16.5 million, which increased $1.8 million, assets held for future use, $4 million, which decreased $55.1 million primarily due to the transfer of Denny substation land to Plant, $54.2 million, which primarily caused an increase of $73.6 million in land and land rights to $150.2 million. The decrease in construction work-in-progress is primarily due to construction work-in-progress capitalization of $535.7 million offset by $436.0 million in additions. The additions in Construction work-in-progress consist mainly of $178.1million in underground and overhead systems, primarily due to Alaskan Way Viaduct, $53.3 million in Generation projects primarily due to Boundary units 51 & 54 rebuild, and Diablo unit 32 rebuild, $52.3 million in stations primarily due to Denny substation, $52.1million in billable service connections, $30.3 million in relicensing costs, $23.9 million in transmission, $15.0 million in general plant, and $13.0 million in data processing system.

See Note 3 Utility Plant of the accompanying financial statements.

2017 Compared to 2016 Utility plant assets net of accumulated depreciation and amortization increased $294.8 million to $3,509.5 million in 2017. Utility plant assets were comprised of hydroelectric production plant $863.6 million which increased $16.6 million, transmission plant, $266.6 million, which increased $24.4 million, distribution plant, $2,500.7 million, which increased $91.8 million, general plant, $384.4 million, which increased $16.0 million, and intangible assets, $577.9 million which increased $34.1 million. The net increase in utility plant assets were partially offset by a $88.1 million increase in Accumulated depreciation and amortization to $1,823.4 million.

The $91.8 million increase in distribution plant is primarily due to $43.0 million for underground system, $16.3 million for transformers, $14.5 million for overhead system, $8.2 million for meters, $6.6 million for poles, and $2.1 million for streetlights. In hydroelectric production, an increase of $16.6 million is primarily due to Ross Bank 42 replacement, Gorge Network automation, Boundary Unit 55 relay protection, and Diablo powerhouse AC panel replacement. The $24.4 million increase in transmission is primarily due to equipment improvements.

Other components of utility plant include Construction work-in-progress $589.3 million which increased $196.8 million, Nonoperating property $14.7 million which increased $2.0 million, Assets held for future use $59.1 million which decreased $0.4 million, and Land and land rights $76.6 million, which increased $1.6 million. The $196.8 million increase in Construction work-in-progress is primarily due to $48.4 million for Denny substation, $23.3 million for Downtown network system, $22.4 million for Alaskan Way Viaduct, $16.4 million for Diablo powerhouse Units 31 & 31 rebuild, $15.1 million for Broad Street sub, $14.5 million for Advanced metering, $11.3 million for PeopleSoft reimplementation, and $45.4 million increases in various other projects.

Restricted Assets

2018 Compared to 2017 Restricted assets consisting of restricted cash increased by $11.3 million to $263.7 million.

Construction funds decreased by $36.2 million to $0.6 million. In 2017, unspent proceeds were from the 2016A Clean Renewable Energy Bonds and 2017C revenue bonds. Bond proceeds are used to fund a portion of the ongoing capital improvement program.

Bond reserve account increased by $24.5 million to $128.1 million from 2018. Sources for the increase were from bond proceeds, interest earnings, and ongoing funding from operating cash to replace the existing surety bond expiring in 2029. The respective additions were $12.2 million, $2.3 million and $10.0 million.

The Rate Stabilization Account (RSA) increased by a net $3.5 million to $96.9 million. A surcharge on electric rates of 1.5% remains in effect since August 2016 until the RSA is funded to $100.0 million. Additions were from the rate surcharge in the amount of $11.6 million and from $1.8 million of interest earnings. These were offset by transfer of funds to operating cash of $9.9 million due to actual net wholesale revenues were less than budgeted. See Note 4 Rate Stabilization Account of the accompanying financial statements.

Other restricted assets increased by $19.5 million to $38.1 million. The Debt service account increased by $9.8 million for debt service due in the beginning of 2019. The balance increase of $9.7 million was primarily for sundry prepayments and higher deposits from communications customers.

2017 Compared to 2016 Restricted assets consisting of restricted cash increased by $30.4 million to $252.4 million.

Construction funds increased by $8.4 million to $36.8 million and represent the balance of unspent proceeds from the 2016A Clean Renewable Energy Bonds issued in January 2016 and 2017C revenue bonds issued in September 2017. Proceeds are being used for on-going funding of a significant portion of the capital improvement program.

Bond reserve account increased by $16.6 million to $103.6 million from bond proceeds and interest earnings. Ongoing funding from operating cash of $10.0 million continued accumulation of the reserve account ahead of the existing surety bond 2029 expiration.

The Rate Stabilization Account (RSA) increased by a net $2.3 million to $93.4 million. A surcharge on electric rates of 1.5% remained in effect implemented in August 2016 until the RSA is funded to $100.0 million. Additions from the rate surcharge of $11.2 million and interest earnings of $1.4 million were offset by transfer of funds to operating cash of $10.3 million because actual net wholesale revenues were less than budgeted.

Other restricted assets increased by $3.1 million to $18.6 million primarily for sundry prepayments and escrow deposits.

Current Assets

2018 Compared to 2017 Current assets increased by $30.4 million to $374.0 million at year end.

Operating cash increased by $6.0 million to $135.1 million at the end of 2018. Increased inflows to cash were from a 5.6% system average rate increase effective in January, RSA surcharge, capital contributions, interest earnings, and reimbursement from the Construction account for capital expenditures. These were offset by lower net wholesale energy sales and payments for higher debt service, transfers to RSA, capital construction projects, and ongoing operations.

Accounts receivable, net, increased by $37.5 million to $128.6 million. The increase was for retail electric sales in the amount of $20.4 million and for large service connections in progress of $16.9 million. Higher receivables totaling $13.1 million were for state tax credits, a rebate from the Advance Metering Infrastructure (AMI) contract in progress, interdepartmental receivables, and other. These were offset by a net increase of $12.1 million in the allowance for retail electric receivables and sundry receivables. The increase of $8.1 million in allowance for Electric Service was in part attributable to the Department's response to customer's concerns on charges from the new billing system and AMI installations. The increase of $4.0 million in allowance for sundry billings was due to higher time and material billings and pole attachment billings that have a slower collection practice because of a slow review process by customers. In addition, interest charges are now being charged to sundry accounts in arrears with the implementation of a new financial system in 2018 that accounted for most of the balance increase in the allowance. Other receivables decreased net $0.8 million in the normal course of operations.

Unbilled revenues decreased by $14.8 million to $74.6 million. The decrease was due to colder weather for the last two months of 2017 compared to 2018 that resulted in higher consumption for the prior year and faster processing of billings as a result of efficiencies gained with the implementation of AMI.

Other current assets increased by $1.8 million to $35.7 million for higher materials and supplies inventory.

2017 Compared to 2016 Current assets increased by $57.1 million to $343.6 million at year end.

Operating cash increased by $56.2 million to $129.1 million at the end of 2017. Increased inflows to cash derived from a 5.6% system average rate increase effective in January, RSA surcharge, capital contributions, and reimbursement from the Construction account for capital expenditures. These were offset by payments for higher debt service, transfers to RSA, lower net wholesale energy sales, capital construction projects, and ongoing operations.

Accounts receivable, net, decreased by $6.7 million to $91.1 million. A total of $11.9 million net increase in receivables were for retail electric due to rate increases and large service connections in progress. These were offset by a net increase of $10.7 million in the allowance for bad debt primarily for retail electric receivables in arrears. Additional net decreases of $7.9 million were for lower inter-departmental billings, grants, receivables from wind renewal energy, and other.

Unbilled revenues increased by $12.8 million to $89.4 million because of the rate increases and higher consumption due to colder weather during the 4th quarter 2017. In addition, a correction to unbilled revenues from 2016 recorded in January 2017 also affected the increase.

Other current assets decreased by $5.2 million to $323.7 million. Materials and supplies inventory was lower by $2.3 million due primarily to issues out to two major projects. The balance decrease was the result of fully allocating inventory loading costs by year end, and including costs held over from 2016.

Other Assets

2018 Compared to 2017 Other assets increased by $15.2 million to $432.0 million. The regulatory asset for environmental cleanup costs increased by $20.6 million, due primarily to the estimated costs to clean up several Superfund sites along the Duwamish River that the Department has been designated a responsible party. Environmental cleanup costs are being recovered through rates over a 25-year period. Initial amortization commenced in 2017. See Note 15 Environmental Liabilities of the accompanying financial statements.

Remaining balance of Other assets decreased by $5.4 million to $318.3 million. Conservation costs, net, decreased by $0.7 million and other assets decreased by $4.7 million. After re-evaluation, $3.6 million of an environmental receivable was no longer considered to be realizable. $1.0 million of the decrease was for ongoing payment of loans from local jurisdictions for underground infrastructure improvements. Remaining balance decrease was primarily due to costs to be allocated associated with use of Department vehicles and labor benefits were expensed by the end of the year compared to having a carryforward balance at the end of 2017.

See Note 7 Other Assets of the accompanying financial statements.

2017 Compared to 2016 Other assets increased by $20.6 million to $416.8 million. The regulatory asset for environmental cleanup costs increased by $10.0 million, due primarily to the estimated cost to clean up the East Waterway Superfund Site.

Remaining balance of Other assets increased by $10.6 million to $323.7 million. Conservation costs, net, increased by $9.8 million. The balance increase of $0.8 million was primarily for ongoing Long term environmental receivables to be paid by other responsible parties for cleanup costs incurred by the Department.

Deferred Outflows of Resources

2018 Compared to 2017 Deferred outflows of resources decreased significantly by $25.3 million to $57.9 million.

In 2015, the Department implemented GASB Statement No. 68, *Accounting and Financial Reporting for Pensions - an amendment of GASB Statement No. 27* concerning accounting for pension plans. For 2018, net decrease of $22.1 million was primarily related to favorable differences between projected and actual investment earnings from the prior year, which decreased from $46.9 million in 2017 to $24.8 million in 2018. See Note 13 Seattle City Employees' Retirement System of the accompanying financial statements.

In 2018, the Department implemented GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits other than Pensions* (OPEB). $2.1 million was recorded as initial deferred outflows of resources. See Note 14 Other Postemployment Benefits of the accompanying financial statements.

Charges on advance refunding decreased a net $5.3 million to $31.0 million. Net activity is the result of additions due to new refunding bond issues and decreases for amortization and advance defeasance of bonds.

2017 Compared to 2016 Deferred outflows of resources decreased by $11.7 million to $83.2 million.

For 2017, the net decrease of $17.7 million was primarily related to the pension plan for differences between projected and actual investment earnings, which decreased from $38.9 million in 2016 to $22.9 million in 2017.

Charges on advance refunding increased a net $6.0 million to $36.3 million.

LIABILITIES

Long-Term Debt

2018 Compared to 2017 Long-term debt increased a net $147.5 million to $2,564.9 million during 2018. The Department issued total new debt in the amount of $263.8 million revenue bonds and $198.8 million refunding revenue bonds to fund a portion of the ongoing capital improvement program. The 2018 bond issues were a combination of fixed and variable rate bonds. $198.2 million in revenue bonds were refunded with a revised variable rate index that anticipates lower interest rate debt over the life of the new variable rate bonds.

Debt to capitalization ratio was 62.4% at the end of 2018, a decrease from the 63.7% ratio of 2017.

Net revenues available to pay debt service were equal to 1.83 times principal and interest on all bonds for 2018.

See Note 9 Long-Term Debt of the accompanying financial statements.

2017 Compared to 2016 Long-term debt increased a net $252.1 million to $2,417.4 million during 2017. The Department issued total new debt in the amount of $485.5 million consisting of revenue bonds to fund a portion of the ongoing capital improvement program and refunding revenue bonds. The 2017 bond issues were a combination of fixed and variable rate bonds. $145.1 million in revenue bonds were refunded with lower interest rate debt.

Debt to capitalization ratio was 63.7% at the end of 2017, a slight increase from the 63.5% ratio of 2016 because of the additional bonds issued.

Net revenues available to pay debt service were equal to 1.85 times principal and interest on all bonds for 2017.

Noncurrent Liabilities

2018 Compared to 2017 Total non-current liabilities decreased by $43.8 million to $365.8 million at the end of 2018.

Net Pension Liability decreased by a net $56.3 million based on the most recent actuarial report and due largely to the strong investment returns during 2017 along with a 1% decrease in the Department's share of the pension liability. See Note 12 Seattle City Employees' Retirement System of the accompanying financial statements.

Environmental liabilities increased by a net $16.4 million to $102.2 million. Environmental liabilities are principally attributable to the estimated cost of remediating contaminated sediments in the lower Duwamish Waterway, a designated federal Superfund site. The Department is considered a potentially responsible party for contamination in the Duwamish River due to land ownership or use of property located along the river. More information on environmental liabilities is found in Note 15 Environmental Liabilities of the accompanying financial statements.

Liabilities for damage claims/lawsuits and worker's compensation decreased a combined $3.5 million based on the most recent actuarial risk report. The balance net decrease of $0.4 million was for nominal changes for compensated absences, post-employment benefits, estimated arbitrage liability for certain bonds, and other.

2017 Compared to 2016 Total non-current liabilities decreased by $24.0 million to $409.6 million at the end of 2017.

Net Pension Liability decreased by a net $29.0 million. The lower liability reflects the effect of certain Department information technology employees transferring to Seattle Information Technology Department (SIT) that occurred in May 2016.

Environmental liabilities increased by a net $3.7 million to $85.8 million. Environmental liabilities are primarily attributable to the estimated cost of remediating contaminated sediments in the lower Duwamish Waterway, a designated federal Superfund site. The Department is considered a potentially responsible party for contamination in the Duwamish River due to land ownership or use of property located along the river.

The balance net increase of $1.3 million was for nominal changes for post-employment benefits, estimated arbitrage liability for certain bonds, and other.

Current Liabilities

2018 Compared to 2017 Current liabilities increased by a net of $35.9 million for a total of $316.6 million at the end of 2018.

Current liability increases totaled $41.5 million. The increase included $21.4 million of usual amounts owed to other City Departments for which payment was delayed in part due to issues encountered in the implementation of the new financial system. Other increases were $7.3 million for customer deposits received for pole attachment projects, $2.4 million for purchased power, and $3.5 million for inventory purchases, customer refunds, and other. Debt service for bonds was higher by $6.0 million.

Current liability decreases totaled $5.6 million. $1.7 million was for lower net taxes, $1.4 million for environmental claims; $1.4 million for payroll accrual, $0.7 million for other claims, and $0.4 million other.

2017 Compared to 2016 Current liabilities increased by a net of $14.2 million for a total of $280.7 million at the end of 2017.

Current liability increases totaling $26.8 million were due to several factors. Increases in customer deposits received for pole attachment projects, retail electric customer overpayments, and escrow retainage were a combined $10.5 million. Debt service for bonds was higher by $7.6 million. Balance net increase of $8.7 million was for payroll, current environmental liabilities, taxes, and other.

Current liability decreases of $12.6 million were for net decrease in vouchers payable for normal operations in the amount of $7.3 million, downward adjustment of $2.8 million primarily for unvouchered inventory received, compensated absences liability of $1.1 million and for paid furlough days from 2016, power payables of $1.0 million, and other of $0.4 million.

Other Liabilities

2018 Compared to 2017 Other liabilities increased by $1.5 million to $37.8 million in 2018. The increase was mostly due to prepayments received for service connection work not yet performed.

2017 Compared to 2016 Other liabilities decreased by $0.9 million to $36.3 million in 2017. Decrease in unearned revenue was the result of increased completions of large service connections offset by increased billings for large service connection projects in progress, both driven by the continued strong local economy.

Deferred Inflows of Resources

2018 Compared to 2017 Deferred inflows of resources increased by $40.3 million for a total of $163.9 million at the end of 2018.

Deferred inflows related to pension liability increased by $31.3 million to $55.1 million and primarily attributable to strong investment returns during 2017. In 2018, the Department implemented the OPEB standard and initially recorded deferred inflows of $2.9 million.

The rate stabilization unearned revenue account increased a net $3.5 million from 2017. The 1.5% surcharge on electric rates in effect since August 2016 contributed $11.6 million, with an offset of $9.9 million transferred to operating revenues for actual net wholesale revenues being lower than budget. $1.8 million in interest income also added to the unearned revenue account leaving an ending balance of $71.9 million in the rate stabilization unearned revenue account. See Note 4 Rate Stabilization Account of the accompanying financial statements.

Other deferred inflows of resources increased by $2.6 million to $34.0 million. The increase was mostly due to payments of $4.9 million received from Bonneville in accordance with the Department's Energy Conservation Agreement less recognition of 2017 BPA Slice true up credit and life-to-date gain from an exchange energy contract terminated in May 2018.

2017 Compared to 2016 Deferred inflows of resources increased by $29.4 million for a total of $123.6 million at the end of 2017.

In 2017, Deferred inflows related to pension liability increased by $23.0 million to $23.8 million and primarily for actuarially determined differences for the Department between employer contributions and proportionate share of contributions affected by the transfer of information technology employees to SIT.

The significant activity occurring since 2010 has been principally the result of implementing, funding, and related activity of the RSA. Funding of the RSA from operating cash has the corresponding effect of deferring operating revenues in the rate stabilization unearned revenue account and vice versa. The rate stabilization unearned revenue account increased a net $2.3 million from 2016.

During 2017, the 1.5% surcharge on electric rates in effect since August 2016 contributed $11.2 million, with an offset of $10.3 million transferred to operating revenues for actual net wholesale revenues being lower than budget. $1.4 million in interest income was also earned, adding to the unearned revenue account, and leaving an ending balance of $68.4 million in the rate stabilization unearned revenue account. See Note 4 Rate Stabilization Account of the accompanying financial statements.

Other deferred inflows of resources increased by $4.1 million to $31.4 million. Again in 2017, the increase was mostly due to payments received from Bonneville in accordance with the Department's Energy Conservation Agreement plus increase for BPA Slice true up credit deferred at the end of 2017.

RESULTS OF OPERATIONS

Condensed Statements of Revenues, Expenses, and Changes in Net Position

	Year Ended December 31		
($ in millions)	**2018**	**2017**	**2016**
Operating revenues	$ 991.6	$ 989.7	$ 903.2
Nonoperating revenues	17.6	13.3	14.6
Total revenues	1,009.2	1,003.0	917.8
Operating expenses	823.2	852.5	795.8
Nonoperating expenses	83.4	75.4	75.1
Total expenses	906.6	927.9	870.9
Income before capital contributions and grants	102.6	75.1	46.9
Capital contributions	59.6	45.1	37.9
Capital grants	-	0.2	0.5
Total capital contributions and grants	59.6	45.3	38.4
Change in net position	$ 162.2	$ 120.4	$ 85.3

SUMMARY

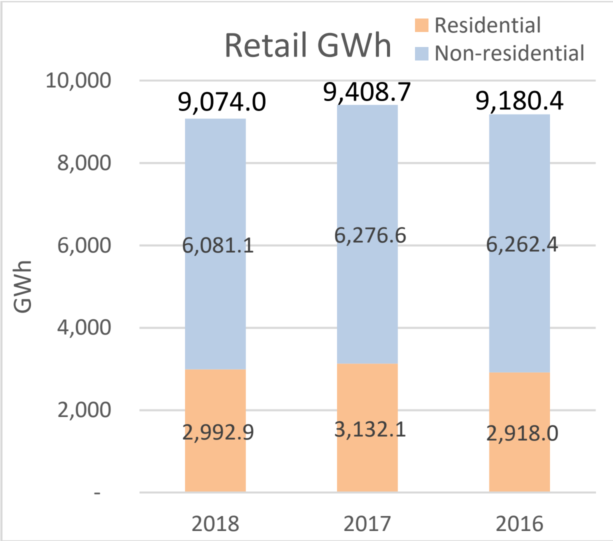
2018 Compared to 2017 Change in net position for 2018 was $162.2 million, an increase of $41.8 million or 34.7% from 2017 change in net position of $120.4 million. Higher retail electric sales attributable to rate increases, including for the 1.5% RSA surcharge, capital contributions, and interest earnings netted with lower unbilled revenue and net Short-term wholesale power revenues contributed to the higher revenues. Lower expenses for long-term purchased power, administrative & general expenses, and taxes also added to the higher change in net position. These were offset by higher bad debt, interest, and other expenses.

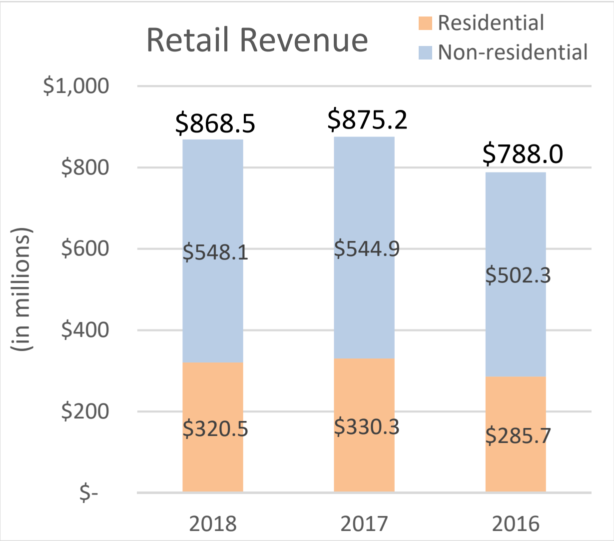
2017 Compared to 2016 Change in net position for 2017 was $120.4 million, an increase of $35.1 million or 41.1% from 2016 change in net position of $85.3 million. Higher retail electric sales attributable to rate increases, including for the 1.5% rate surcharge, and capital contributions were offset by lower net Short-term wholesale power revenues and higher long-term purchased power, bad debt, administrative & general, taxes, and depreciation.

REVENUES

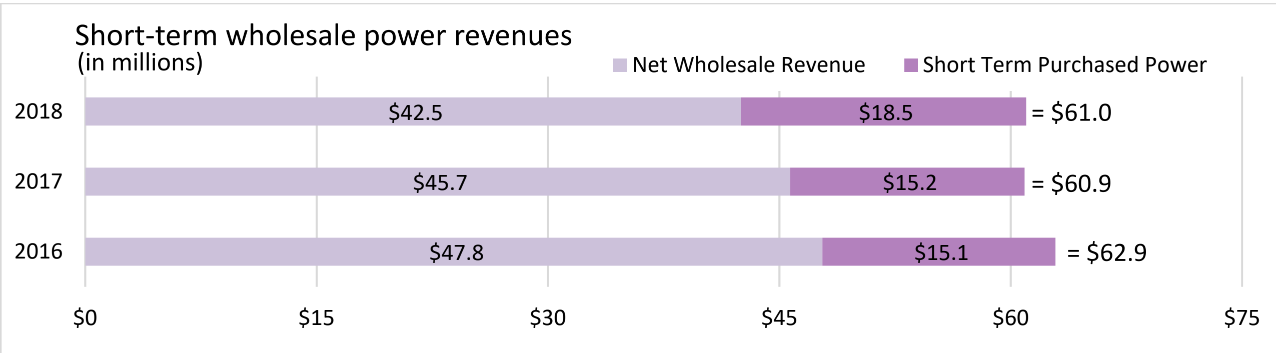
2018 Compared to 2017 Total operating revenues were $991.6 million, an increase of $1.9 million or 0.2% from 2017. Retail power revenues at $868.6 million decreased $6.6 million, Short-term wholesale power revenues of $61.0 million increased $0.1 million, Other power-related revenues at $45.9 million increased $10.1 million, Transfers from/(to) RSA at ($3.5) million decreased $1.2 million, and Other operating revenues at $19.6 million decreased $0.5 million.

Retail power revenues were higher due to the 5.6% system rate increase effective January 1, 2018, and the 1.5% rate surcharge, in effect since August 1, 2016. Consumption was lower by 1.1% for residential customers and by 0.7% for non-residential customers due in part to the warmer weather during the last two months of the year. Energy conservation and newly constructed energy efficient buildings also contributed to the lower consumption. These components also affected the lower unbilled revenue compared to 2017. Transactions within Transfers from/(to) rate stabilization account are affected in part by actual net wholesale power revenues compared to budget. In 2018, actual net wholesale power revenues were lower than budget by $9.9 million and this amount was transferred from the rate stabilization unearned revenue account. This was offset by the RSA rate surcharge revenues of $11.6 million and interest earnings of $1.8 million for a net ($3.5) million transferred to the rate stabilization unearned revenue account. In 2017, comparable net transfers to the rate stabilization unearned revenue account were ($2.3) for an overall decrease of $1.2 million between years.





Net Short-term wholesale power revenues were $42.5 million, a decrease of $3.2 million or 7.0% from net Short-term wholesale power revenues of $45.7 million in 2018. Net Short-term wholesale power revenues represent revenue received from the sale of power generated in excess of system sales and other obligations. Net short-term wholesale power revenues fluctuate with changes in water conditions, retail sales and economic factors such as the price of natural gas. Lower generator availability during 2nd quarter also influenced the lower net Short-term wholesale power revenues. A British Columbia pipeline explosion in October caused a temporary increase in energy prices which positively affected net Short-term wholesale power revenues. Other net power-related revenues increased by $0.9 million. Valuation of energy exchange contracts increased by $10.1 million due to higher market prices and other ancillary contracts. These were offset by the higher valuation of energy exchange expenses as discussed below.



2017 Compared to 2016 Total operating revenues were $989.7 million, an increase of $86.5 million or 9.6% from 2016. Retail power revenues at $875.2 million increased $87.2 million, Short-term wholesale power revenues at $60.9 million decreased $2.0 million, Other power-related revenues at $35.8 million increased $3.2 million, Transfers from/(to) RSA at ($2.3) million decreased $2.2 million, and Other operating revenues at $20.1 million increased $0.3 million.

Retail power revenues were higher due to the 5.6% across-the-board rate increase effective January 1, 2017, and the RSA rate surcharge, in effect since August 1, 2016. Higher consumption due to the colder weather during the first two months of the year was another element contributing to the higher revenues. Transactions within Transfers from/(to) rate stabilization account are affected in part by actual net wholesale power revenues compared to budget. In 2017, actual net wholesale power revenues were lower than budget by $10.3 million and this amount was transferred from the rate stabilization unearned revenue account. This was offset by the RSA rate surcharge revenues of $11.2 million and interest earnings of $1.4 million for a net ($2.3) million transferred to the rate stabilization unearned revenue account. In 2016, net transfers to rate stabilization unearned revenue account were ($0.1), the result of comparable transactions with different amounts and hence, an overall decrease of $2.2 million between years.

Net Short-term wholesale power revenues were $45.7 million, a decrease of $2.1 million or 4.4% from net Short-term wholesale power revenues of $47.8 million in 2016. The decrease from 2016 was primarily due to lower net energy sales volume affected somewhat by higher average wholesale power prices. Other net power-related revenues, including valuation of energy exchange revenues increased by a net $2.3 million due in part to additional ancillary contracts in 2017.

EXPENSES

2018 Compared to 2017 Operating expenses totaled $823.2 million, a decrease of $29.3 million or 3.4% from $852.5 million in 2017.

Power-related operating expenses at $360.7 million were higher by $2.8 million or 0.8%. These expenses were comprised of Long-term purchased power - Bonneville and other of $217.8 million, which decreased $7.0 million, Short-term wholesale power purchases of $18.5 million, which increased $3.3 million, Other power expenses of $70.2 million, which increased $4.8 million, and Transmission of $54.2 million, which increased $1.7 million.

Bonneville costs decreased largely because of shifting to purchase only Block power effective October 2017, and thereby reducing Slice power purchases. A final higher Bonneville Slice true-up credit also added to the lower Bonneville costs. These were offset by higher Short-term wholesale power purchases necessary for managing load and Power related wholesale purchases primarily for higher fair valued power exchange contracts which increased by $9.2 million. Other power expenses decreased mainly because of the one-time expense in 2017 for abandoned plan to replace the AC/DC electrical supply system at the Skagit Ross Dam did not recur. Other power related variances were minimal for normal operations.

Non-power operating expenses decreased by $24.3 million to $246.7 million or 9.0% from $271.0 million in 2017. These expenses included Distribution expenses of $61.7 million, which increased $1.5 million, Customer service of $55.7 million, which increased $6.3 million, Conservation of $32.9 million, which increased $0.4 million, and Administrative and general (A&G), net, of $96.2 million which decreased $32.5 million.

Customer service expenses experienced higher bad debt expense for retail electric sales and sundry billings. Customary collection activities and late fees were modified during most of year in response to billing concerns from retail electric customers. Usual collection and related activities resumed in November. Sundry billings bad debt expense was higher because of related increase in allowance for older aged receivables concerning time and material billings and pole attachment billings that have a slower review process by customers. Interest charges in arrears now assessed with the new financial system also contributed to the higher bad debt expense. Balance of increase for Customer service was for normal operations.

Net changes for Distribution and Conservation expenses were nominal and part of normal operations.

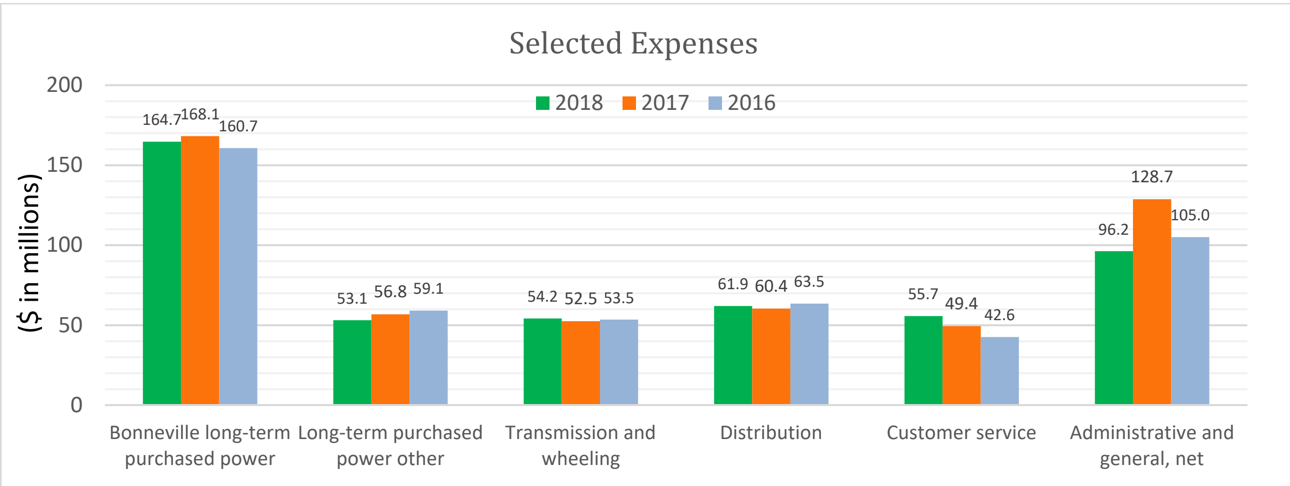
Administrative and general (A&G), net, was considerably lower by $32.5 million for a total of $96.2 million. This was due to A&G cost reductions of $16.8 million combined with a $15.7 million larger transfer of costs from A&G to capital projects that had the net effect of reducing A&G, net.

The Cost reductions included a $13.1 million lower annual adjustment to the net pension expense required by GASB Statement No. 68 than was recorded in 2017 because of strong investment returns. Estimated expenses for claims/lawsuits and workers compensation decreased a combined $7.2 million based on the most recent actuarial report for respective estimated losses. General year-end estimated accruals were also lower by $4.3 million. There were cost increases of $7.8 million for higher general fund cost allocations, COLA salary adjustments, general plant maintenance, and other.

The higher A&G cost transfer of $15.7 million was due to different allocation process with implementation of the new financial system combined with an increase in the amount of capital work during 2018.

Taxes at $91.8 million decreased by $3.0 million. Higher taxes due to increased billed retail electric revenue were offset by favorable tax credits at the end of the year. Tax credits were higher for solar energy participants and for interdepartmental streetlights revenue allowed for the period January 2013 – June 2017 from a recent state tax audit.

Depreciation and amortization at $124.0 million decreased by $4.8 million due mainly to retirements and certain high depreciation assets transitioning to fully depreciated by the end 2018.



2017 Compared to 2016 Operating expenses totaled $852.5 million, an increase of $56.7 million or 7.1% from $795.8 million in 2016.

Power-related operating expenses at $357.9 million were higher by $9.4 million or 2.7%. These expenses were comprised of Long-term purchased power - Bonneville and other of $224.8 million, which increased $5.0 million, Short-term wholesale power purchases of $15.2 million, which increased $0.1 million, Other power expenses of $65.4 million, which increased $5.3 million, and Transmission of $52.5 million, which decreased $1.0 million.

Bonneville costs increased largely because of changing to Block power purchases only, effective October 2017, and thereby reducing Slice power purchases. A lower Bonneville Slice true-up credit also added to the higher Bonneville costs. These were offset by lower other Long-term purchased power costs primarily for less renewable wind energy due to weather dependency. Other power expenses increased because of higher operating costs, including for an abandoned plan to replace the AC/DC electrical supply system at the Skagit Ross Dam. Other power related variances were minimal for normal operations.

Non-power operating expenses increased by $29.7 million to $271.0 million or 29.7% from $241.3 million in 2016. These expenses included Distribution expenses of $60.4 million, which decreased $3.1 million, Customer service of $49.4 million, which increased $6.8 million, Conservation of $32.5 million, which increased $2.3 million, and Administrative and general (A&G), net, of $128.7 million which increased $23.7 million.

Distribution expenses were lower in several categories including for underground system network maintenance, contracting and support services, fewer wireless antenna upgrades, lower street lighting maintenance due to use of LEDs, and other. Customer service expenses continued to be driven primarily by higher bad debt expense for retail electric sales because of higher balances in aged receivables, as these accounts are processed through collection.

Administrative and general, net, were significantly higher for SIT expenses as these billings were consolidated within A&G. In prior years, technology expenses were recorded throughout capital and operations projects (total SIT costs for 2017 and 2016 were comparable). Other increases were for COLA salary adjustments, general year-end estimated accruals, and compensated absences. These were offset by lower general plant maintenance, lower pension and benefits from the transfer of staff to SIT, industrial insurance, and other.

Taxes at $94.8 million increased by $9.6 million because of the higher revenues. Depreciation and amortization at $128.8 million increased by $8.0 million generally due to additional plant assets placed in service, including for the retail power billing system implemented in 4th quarter 2016.

NONOPERATING REVENUES AND (EXPENSES), CAPITAL CONTRIBUTIONS AND GRANTS

2018 Compared to 2017 Nonoperating revenues increased by $4.3 million to $17.6 million in 2018. The largest increase was for higher interest earnings totaling $3.9 million on account of a higher rate of return for the city cash pool, higher interest earnings on bond proceeds, and a lower unrealized loss fair value adjustment for pooled investments. Remaining balance increase was in line with normal operations.

Nonoperating expenses at $83.4 million were higher by $8.0 million. Higher interest because of higher bonds outstanding in 2018 along with increased refunding loss amortization were offset by a slight increase in interest charged to construction projects and higher bond premium amortization.

Capital contributions and grants increased by $14.3 million to $59.6 million in 2018. The increase was due to increased activity for pole attachment projects, increased large service connections and related higher amperage fees charged, all due in part to the strong local economy. There were no capital grants in 2018.

2017 Compared to 2016 Nonoperating revenues decreased by $1.3 million to $13.3 million in 2017. There was no Washington State Department of Ecology grant reimbursement received in 2017 compared to the prior year. This was offset by higher unrealized gains on pooled investments due to favorable investment market performance, higher interest earnings from bond proceeds for two bond issues, and higher surplus property sales.

Nonoperating expenses at $75.4 million were slightly higher by $0.3 million. Higher interest on greater average balance of bonds outstanding in 2017 along with higher refunding loss amortization were offset by increased interest charged to construction projects and bond premium amortization.

Capital contributions and grants increased by $6.9 million to $45.3 million in 2017. The increase was due for the most part to an increase in new amperage fees charged to large service connections and service work charged to telecommunications companies.

RISK MANAGEMENT

The Department began implementing an Enterprise-wide Risk Management (ERM) process in 2008 to establish a full spectrum approach to risk management that links important decision-making functions through a standardized process of identifying, assessing, monitoring, and mitigating risks across all Business Units and Divisions of the Department.

Risk Oversight Council (ROC) oversees wholesale power marketing activities. It is comprised of the Chief Financial Officer (Chair/Voting), Power Supply Officer (Voting), Director of Risk Oversight (Voting), Director of Power Management (non-Voting), Director of Power Contracts, Regional Affairs & Strategic Planning (non-Voting), and Director of Finance (non-Voting). ROC guides the continuous improvement of energy risk management activities and capabilities, approves hedging strategies, hedging plans, and approves changes to relevant operating procedures.

The Risk Oversight Division, in addition to the ERM, manages the market and credit risk related to all wholesale marketing activities, and carries out the middle office functions of the Department. This includes confirmations, risk controls, deal review & valuations, independent reporting of market positions, counterparty credit risk, risk modeling, model validations, settlements, and ensuring adherence to Wholesale Energy Risk Management (WERM) policy and procedures.

Hydro Risk

Due to the Department's primary reliance on hydroelectric generation, weather can significantly affect its operations. Hydroelectric generation depends on the amount of snow-pack in the mountains upstream of the Department's hydroelectric facilities, springtime snow-melt, run-off and rainfall. Hydroelectric operations are also influenced by flood control and environmental matters, including protection of fish. In low-water years, the Department's generation is reduced, and the use of wholesale purchased power may increase in order to meet load. Normally, the Department experiences electricity usage peaks in winter; however, extreme weather conditions affecting either heating or cooling needs could cause the Department's seasonal fluctuations to be more pronounced and increase costs. In addition, economic trends (increase or decrease in business activity, housing sales and development of properties) can affect demand and change or increase costs.

Energy Market Risk

For the Department, energy market risk is the risk of adverse fluctuations in the price of wholesale electricity, which is compounded by volumetric changes affecting the availability of, or demand for electricity. Factors that contribute to energy market risk include: regional planned and unplanned generation plant outages, transmission constraints or disruptions, the number of active creditworthy market participants willing to transact, and environmental regulations that influence the availability of generation resources.

The Department's exposure to hydro volumetric and energy market risk is managed by the ROC and the approved strategies are executed by the Power Management Division. The Department engages in market transactions to meet its load obligations and to realize earnings from surplus energy resources.

With significant portion of the Department's revenue expected from wholesale energy market sales, great emphasis is placed on the management of risks associated with this activity. Policies, procedures, and processes designed to manage, control and monitor these risks are in place. A formal front, middle, and back office structure is in place to ensure proper segregation of duties.

The Department measures the risk in its energy portfolio using a model that utilizes historical simulation methodology and incorporates not only price risk, but also the volumetric risk associated with its hydro-dominated power portfolio. Scenario analysis is used for stress testing.

Credit Risk

Credit risk is the risk of loss that would be incurred as a result of nonperformance by a counterparty of their contractual obligations. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Department may find it necessary to procure electricity at current market prices, which may be higher than the contract price. If a counterparty failed to pay its obligation in a timely manner, this would have an impact on the Department's revenue and cash flow. As with market risk, the Department has policies governing the management of credit risk.

Wholesale counterparties are assigned credit limits based on publicly available and proprietary financial information. Along with ratings provided by national ratings agencies, an internal credit scoring model is used to classify counterparties into one of several categories with permissible ranges of credit limits. Specific counterparty credit limits are set within this prescribed range based on qualitative and quantitative factors. Credit limits are also used to manage counterparty concentration risk. The Department actively strives to reduce concentration of credit risk related to geographic location of counterparties as it only transacts in the western energy markets. This geographic concentration of counterparties may impact the Department's overall credit exposure, because counterparties may be affected by similar conditions.

Credit limits, exposures and credit quality are actively monitored daily. Despite such efforts, there is potential for default, however the Department has not faced a counterparty default in nearly 15 years. The Department transacts with counterparties on an uncollateralized and collateralized basis. Posted collateral may be in the form of cash, letters of credit, or parental guarantees.

REQUESTS FOR INFORMATION

For more information about Seattle City Light, contact Marketing and Communications at 206-684-3090 or at P.O. Box 34023, Seattle, WA 98124-4023.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

BALANCE SHEETS - ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

AS OF DECEMBER 31, 2018 AND 2017

($ in millions)	2018	2017
ASSETS		
UTILITY PLANT—At original cost:		
Plant-in-service—excluding land	$ 5,057.7	$ 4,593.2
Less accumulated depreciation and amortization	(1,893.8)	(1,823.4)
Total plant-in-service—net	3,163.9	2,769.8
Construction work-in-progress	486.2	589.3
Nonoperating property—net of accumulated depreciation	16.5	14.7
Assets held for future use	4.0	59.1
Land and land rights	150.2	76.6
Total utility plant—net	3,820.8	3,509.5
RESTRICTED ASSETS:		
Rate stabilization account	96.9	93.4
Municipal light and power bond reserve account	128.1	103.6
Construction account	0.6	36.8
Special deposits and other restricted assets	38.1	18.6
Total restricted assets	263.7	252.4
CURRENT ASSETS:		
Cash and equity in pooled investments	135.1	129.1
Accounts receivable (includes $ - and $1.6 at fair value), net of allowance of $33.6 and $21.4	122.6	88.8
Interfund receivables	6.0	2.3
Unbilled revenues	74.6	89.4
Materials and supplies at average cost	35.4	33.6
Prepayments and other current assets	0.3	0.4
Total current assets	374.0	343.6
OTHER ASSETS:		
Conservation costs—net	261.5	262.2
Environmental costs—net	113.7	93.1
Other charges and assets—net	56.8	61.5
Total other assets	432.0	416.8
TOTAL ASSETS	4,890.5	4,522.3
DEFERRED OUTFLOWS OF RESOURCES		
Deferred outflows related to Pension and OPEB	26.9	46.9
Charges on advance refunding	31.0	36.3
TOTAL DEFERRED OUTFLOWS OF RESOURCES	57.9	83.2
TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES	$ 4,948.4	$ 4,605.5

See notes to financial statements.

BALANCE SHEETS - LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION
AS OF DECEMBER 31, 2018 AND 2017

($ in millions)	2018	2017
LIABILITIES		
LONG-TERM DEBT:		
Revenue bonds	$ 2,491.6	$ 2,345.5
Plus bond premium—net	192.7	190.7
Less revenue bonds—current portion	(119.4)	(118.8)
Total long-term debt	2,564.9	2,417.4
NONCURRENT LIABILITIES:		
Net pension liability	232.5	288.8
Accumulated provision for injuries and damages	108.9	96.1
Compensated absences	15.0	15.7
Other noncurrent liabilities	9.4	9.0
Total noncurrent liabilities	365.8	409.6
CURRENT LIABILITIES:		
Accounts payable and other current liabilities	112.4	102.1
Interfund payables	33.4	12.0
Accrued payroll and related taxes	13.8	15.3
Compensated absences	1.2	1.5
Accrued interest	36.4	31.0
Long-term debt—current portion	119.4	118.8
Total current liabilities	316.6	280.7
OTHER LIABILITIES	37.8	36.3
TOTAL LIABILITIES	3,285.1	3,144.0
DEFERRED INFLOWS OF RESOURCES		
Rate stabilization unearned revenue	71.9	68.4
Deferred inflows related to pension and OPEB	58.0	23.8
Other deferred inflows of resources (includes $ - and $0.8 at fair value)	34.0	31.4
TOTAL DEFERRED INFLOWS OF RESOURCES	163.9	123.6
NET POSITION		
Net investment in capital assets	1,523.8	1,382.8
Restricted:		
Rate stabilization account	25.0	25.0
Special deposits and other purposes	-	-
Total restricted	25.0	25.0
Unrestricted—net	(49.4)	(69.9)
Total net position	1,499.4	1,337.9
TOTAL LIABILITIES, DEFERRED INFLOWS OF RESOURCES, AND NET POSITION	$ 4,948.4	$ 4,605.5

See notes to financial statements.

THIS PAGE IS INTENTIONALLY LEFT BLANK

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

STATEMENTS OF REVENUES, EXPENSES, AND CHANGES IN NET POSITION
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

($ in millions)	2018	2017
OPERATING REVENUES:		
Retail power revenues	$ 868.6	$ 875.2
Short-term wholesale power revenues	61.0	60.9
Other power-related revenues	45.9	35.8
Transfers from/(to) rate stabilization account	(3.5)	(2.3)
Other operating revenues	19.6	20.1
Total operating revenues	991.6	989.7
OPERATING EXPENSES:		
Long-term purchased power—Bonneville and other	217.8	224.8
Short-term wholesale power purchases	18.5	15.2
Other power expenses	70.2	65.4
Transmission	54.2	52.5
Distribution	61.9	60.4
Customer service	55.7	49.4
Conservation	33.0	32.5
Administrative and general	96.2	128.7
Taxes	91.8	94.8
Depreciation and amortization	123.9	128.8
Total operating expenses	823.2	852.5
OPERATING INCOME	168.4	137.2
NONOPERATING REVENUES AND (EXPENSES):		
Other revenues and (expenses)—net	17.6	13.3
Interest expense		
Interest expense—net	(96.2)	(86.6)
Amortization of bond costs—net	12.8	11.2
Total interest expense	(83.4)	(75.4)
Total nonoperating expenses	(65.8)	(62.1)
INCOME BEFORE CAPITAL CONTRIBUTIONS AND GRANTS	102.6	75.1
CAPITAL CONTRIBUTIONS AND GRANTS:		
Capital contributions	59.6	45.1
Capital grants	-	0.2
Total capital contributions and grants	59.6	45.3
CHANGE IN NET POSITION	162.2	120.4
NET POSITION:		
Beginning of year	1,337.9	1,217.5
Adjustment for the implementation of GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*	(0.7)	-
Beginning of year, as adjusted	1,337.2	1,217.5
End of year	$ 1,499.4	$ 1,337.9

See notes to financial statements.

THE CITY OF SEATTLE—CITY LIGHT DEPARTMENT

STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

($ in millions)	2018	2017
OPERATING ACTIVITIES:		
Cash received from customers and counterparties	$ 965.0	$ 957.2
Cash paid to suppliers and counterparties	(333.3)	(327.2)
Cash paid to employees	(158.7)	(165.2)
Taxes paid	(92.6)	(92.9)
Net cash provided by operating activities	380.4	371.9
NONCAPITAL FINANCING ACTIVITIES:		
Interfund operating cash received	1.2	2.0
Interfund operating cash paid	(39.1)	(30.2)
Principal paid on long-term debt	(10.7)	(8.6)
Interest paid on long-term debt	(9.2)	(8.2)
Noncapital grants received (paid)	0.6	(0.3)
Bonneville receipts for conservation	6.6	5.2
Payment to vendors on behalf of customers for conservation	(24.2)	(31.8)
Net cash used in noncapital financing activities	(74.8)	(71.9)
CAPITAL AND RELATED FINANCING ACTIVITIES:		
Proceeds from long-term debt	462.5	485.5
Proceeds from long-term debt premiums	20.1	54.8
Payment to trustee for defeased bonds	(198.2)	(163.6)
Bond issue costs paid	(2.2)	(1.5)
Principal paid on long-term debt	(107.5)	(104.4)
Interest paid on long-term debt	(91.6)	(88.1)
Acquisition and construction of capital assets	(401.6)	(418.1)
Interfund payments for acquisition and construction of capital assets	(12.9)	(28.9)
Capital contributions	28.9	37.4
Interfund receipts for capital contributions	0.7	1.5
Capital grants received/(paid)	(0.1)	3.2
Interest received for suburban infrastructure improvements	2.6	2.3
Proceeds on sale of property	-	0.8
(Increase) Decrease in other assets	2.1	0.9
Net cash used in capital and related financing activities	(297.2)	(218.2)
INVESTING ACTIVITIES:		
Interest received on cash and equity in pooled investments	8.9	4.8
Net cash provided by investing activities	8.9	4.8
NET INCREASE (DECREASE) IN CASH AND EQUITY IN POOLED INVESTMENTS	17.3	86.6
CASH AND EQUITY IN POOLED INVESTMENTS:		
Beginning of year	381.5	294.9
End of year	$ 398.8	$ 381.5

See notes to financial statements.

STATEMENTS OF CASH FLOWS - RECONCILIATION
FOR THE YEARS ENDED DECEMBER 31, 2018 AND 2017

($ in millions)	2018	2017
RECONCILIATION OF OPERATING INCOME TO NET CASH PROVIDED BY OPERATING ACTIVITIES:		
Operating income	$ 168.4	$ 137.2
Adjustments to reconcile operating income to net cash provided by operating activities:		
Non-cash items included in operating income:		
Depreciation	129.5	136.1
Amortization of other liabilities	(1.7)	(1.5)
Amortization of other assets	29.9	28.9
Bad debt expense	19.9	14.6
Power revenues	(30.7)	(31.5)
Power expenses	33.2	30.6
Provision for injuries and damages	4.1	(0.4)
Other non-cash items	9.1	19.9
Change in:		
Accounts receivable	(0.5)	20.5
Unbilled revenues	14.7	(12.8)
Materials and supplies	(5.6)	8.1
Prepayments, interest receivable, and other receivables	(4.5)	4.8
Other assets	2.5	(1.9)
Provision for injuries and damages and claims payable	(13.7)	(5.5)
Accounts payable and other payables	22.3	22.5
Rate stabilization unearned revenue	3.5	2.3
Total adjustments	212.0	234.7
Net cash provided by operating activities	$ 380.4	$ 371.9
SUPPLEMENTAL DISCLOSURES OF NONCASH ACTIVITIES:		
In-kind capital contributions	$ 3.4	$ 0.5
Amortization of debt related costs—net	12.8	11.2
Allowance for funds used during construction	12.1	12.0
Power exchange revenues	17.5	15.0
Power exchange expenses	(18.3)	(15.0)
Power revenue netted against power expenses	5.9	5.4
Power expense netted against power revenues	(8.6)	(9.8)

See notes to financial statements.

1. OPERATIONS AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The City Light Department (the Department) is the public electric utility of The City of Seattle (the City). The Department is an enterprise fund of the City. The Department owns and operates certain generating, transmission, and distribution facilities and supplies electricity to approximately 461,500 residential, commercial, and public customers in the city of Seattle. The Department also supplies electrical energy to other City agencies at rates prescribed by City ordinances, and to certain neighboring communities under franchise agreements. The establishment of the Department's rates is within the exclusive jurisdiction of the Seattle City Council. A requirement of Washington State law provides that rates must be fair, nondiscriminatory, and fixed to produce revenue adequate to pay for operation and maintenance expenses and to meet all debt service requirements payable from such revenue. The Department pays occupation taxes to the City based on total revenues.

The Department's revenues for services provided to other City departments were $20.0 million and $17.9 million in 2018 and 2017, respectively, and $1.8 million and $2.9 million for non-energy services, respectively.

The Department receives certain services from other City departments and paid $113.4 million in 2018 and $108.0 million in 2017, for such services. Amounts paid include central cost allocations from the City for services received including treasury services, risk financing, purchasing, data processing systems, vehicle maintenance, personnel, payroll, legal, administrative, information technology and building rentals, including for the Department's administrative offices.

The Department's receivables from other City departments totaled $6.0 million and $2.3 million at December 31, 2018, and 2017, respectively. The Department's payables to other City departments totaled $33.4 million and $12.0 million at December 31, 2018, and 2017, respectively. The balances receivable and payable are the result of transactions incurred in the normal course of operations.

Basis of Presentation and Accounting Standards—The financial statements are prepared using the economic resources measurement focus and the accrual basis of accounting in conformity with accounting principles generally accepted in the United States of America as applied to governmental units. Revenues are recorded when earned and expenses are recorded when a liability is incurred, regardless of the timing of related cash flows. The Governmental Accounting Standards Board (GASB) is the accepted standard-setting body for establishing governmental accounting and financial reporting principles. The Department has applied and is current through 2018 with all applicable GASB pronouncements.

The GASB has issued Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions*, replacing the requirements of Statements No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other Than Pensions*, as amended, and No. 57, *OPEB Measurements by Agent Employers and Agent Multiple-Employer Plans*. This Statement establishes new accounting and financial reporting requirements for governments whose employees are provided with OPEB, including the recognition and measurement of liabilities, deferred outflows of resources, deferred inflows of resources and expense. The Department implemented Statement No. 75 effective January 1, 2018. See Note 14 Other Postemployment Benefits and Note 21 Implementation of New Accounting Standards.

The GASB has issued Statement No. 83, *Certain Asset Retirement Obligations*, which establishes criteria for determining the timing and pattern of recognition of a liability and a corresponding deferred outflow of resources for legally enforceable asset retirement obligations and requires that recognition occur when the liability is both incurred and reasonably estimable. This standard will be adopted by the Department in 2019. The Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

The GASB has issued Statement No. 84, *Fiduciary Activities*, which improves guidance regarding the identification of fiduciary activities, including pension plans and other postemployment benefits, for accounting and financial reporting purposes and how those activities should be reported. Statement No. 84 will be effective for the Department in 2019 and the Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

The GASB has issued Statement No. 87, *Leases*, which improves accounting and financial reporting for leases by governments. This Statement increases the usefulness of governments' financial statements by requiring recognition of certain lease assets and liabilities for leases that previously were classified as operating leases and recognized as inflows of resources or outflows of resources based on the payment provisions of the contract. Statement No. 87 will be effective for the Department in 2020 and the Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

The GASB has issued Statement No. 88, *Certain Disclosures Related to Debt, including Direct Borrowings and Direct Placements*, which improves the information that is disclosed in notes to government financial statements related to debt, including direct borrowings and direct placements. This Statement also clarifies which liabilities governments should include when disclosing information related to debt. Statement No. 88 will be effective for the Department in 2019 and the Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

The GASB has issued Statement No. 89, *Accounting for Interest Cost Incurred before the End of a Construction Period*, which enhances the relevance and comparability of information about capital assets and the cost of borrowing for a reporting period and simplifies accounting for interest cost incurred before the end of a construction period. Statement No. 89 will be effective for the Department in 2020. The Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

The GASB has issued Statement No. 90, *Majority Equity Interests*, which improves the consistency and comparability of reporting a government's majority equity interest in a legally separate organization and improves the relevance of financial statement information. Statement No. 90 will be effective in 2019 and the Department is currently evaluating the impact the adoption of this statement will have on its financial statements.

Fair Value Measurements—Descriptions of the Department's accounting policies on fair value measurements for items reported on the balance sheets at December 31, 2018 and 2017, are as noted in Note 2 Fair Values, Note 5 Cash and Equity in Pooled Investments and Investments, Note 6 Accounts Receivable and Note 19 Long-Term Purchased Power, Exchanges, and Transmission.

Fair Value of Financial Instruments—The Department's financial instruments reported on the balance sheets at December 31, 2018 and 2017, as Restricted assets and Cash and equity in pooled investments are measured at fair value. These instruments consist primarily of the Department's share of the City-wide pool of investments (see Note 5 Cash and Equity in Pooled Investments and Investments). Gains and losses on these financial instruments are reflected in Investment income in the statements of revenues, expenses, and changes in net position. The fair value of long-term debt at December 31, 2018 and 2017 is discussed in Note 9 Long-Term Debt.

Net Position**—**The Department classifies its net position into three components as follows:

- *Net investment in capital assets*—This component consists of capital assets, net of accumulated depreciation and amortization, reduced by the net outstanding debt balances related to capital assets net of unamortized debt expenses.

- *Restricted*—This component consists of net position with constraints placed on use. Constraints include those imposed by creditors (such as through debt covenants and excluding amounts considered in net capital, above), grants, or laws and regulations of other governments, or by enabling legislation, The City of Seattle Charter, or by ordinances legislated by the Seattle City Council.

- *Unrestricted*—This component consists of assets and liabilities that do not meet the definition of Net investment in capital assets or Restricted.

Restricted and Unrestricted Net Position—The Department's policy is to use restricted net position for specified purposes and to use unrestricted net position for operating expenses. The Department does not currently incur expenses for which both restricted and unrestricted net position is available.

Assets Held for Future Use**—**These assets include property acquired but never used by the Department in electrical service and therefore, held for future service under a definitive plan. Also included is property previously used in service but retired and held pending its reuse in the future under a definitive plan. As of December 31, 2018, and 2017, assets held for future use included the following electrical plant assets: land for future substations, communication system and risk mitigation structures totaling $4.0 million and $59.1 million, respectively.

Materials and Supplies**—**Materials and supplies are generally used for construction, operation and maintenance work, not for resale. They are valued utilizing the average cost method and charged to construction or expense when used.

Revenue Recognition**—**Service rates are authorized by City ordinances. Billings are made to customers on a monthly or bimonthly basis. Revenues for energy delivered to customers between the last billing date and the end of the year are estimated and reflected in the accompanying financial statements as unbilled revenue within Retail power revenues.

The Department's customer base accounted for electric energy sales at December 31, 2018 and 2017, as follows:

	2018	2017
Residential	36.9 %	37.7 %
Nonresidential	63.1 %	62.3 %
Total	100.0 %	100.0 %

Revenues earned in the process of delivering energy to customers, wholesale energy transactions, and related activities are considered operating revenues in the determination of change in net position. Investment income, nonexchange transactions, and other revenues are considered Nonoperating revenues.

Expense Recognition**—**Expenses incurred in the process of delivering energy to customers, wholesale energy transactions, and related activities are considered operating expenses in the determination of net income. Debt interest expense, debt related amortization, and certain other expenses are considered Nonoperating expenses.

Administrative and General Overhead Costs Applied**—**Certain administrative and general overhead costs are allocated to construction work-in-progress, major data processing systems development, programmatic conservation, relicensing mitigation projects, and billable operations and maintenance activities based on rates established by cost studies. Pension and benefit costs are allocated to capital and operations and maintenance activities based on a percentage of labor dollars. The administrative and general overhead costs applied totaled $65.8 million and $50.1 million in 2018 and 2017, respectively. Benefit costs applied were $25.9 million and $57.1 million in 2018 and 2017, respectively. Administrative and general expenses, net of total applied overhead, were $96.2 million and $128.7 million in 2018 and 2017, respectively.

Interest Charged to Construction**—**Interest is charged for funds used during construction of plant assets and to non-billable construction work-in-progress. Interest charged represents the estimated costs of financing construction projects and is computed using the Department's weighted-average interest rate for all bonds outstanding, the majority of which are tax exempt, and is revised when new bonds are issued and at the end of the year. Interest charged to construction totaled $12.1 million and $12.0 million in 2018 and 2017, respectively, and is reflected as a reduction of Interest expense in the statements of revenues, expenses, and changes in net position.

Nonexchange Transactions**—**Capital contributions and grants in the amount of $59.6 million and $45.3 million for 2018 and 2017, respectively, and noncapital grants in the amount of $48 thousand and $211 thousand for 2018 and 2017, respectively, are reported in the statements of revenues, expenses, and changes in net position as nonoperating revenues from nonexchange transactions. Capital contributions and grants revenues are recognized based on the accrual basis of accounting. In-kind capital contributions are recognized at estimated acquisition value in the period when all eligibility requirements have been met as described in GASB Statement No. 33, *Accounting and Financial Reporting for Nonexchange Transactions*. Federal and state grant revenues are recognized as earned and are subject to contract and other compliance audits.

Compensated Absences—Regular employees of the Department earn vacation time in accordance with length of service. A maximum of 480 hours may be accumulated for the most tenured employees and, upon termination, employees are entitled to compensation for unused vacation. Upon retirement, employees receive compensation equivalent to 25% of their accumulated sick leave. Effective 2006, only employees represented by unions who voted in favor of a Healthcare Reimbursement Arrangement (HRA) receive 35% of their sick leave balance tax-free through an HRA account for healthcare expenses post retirement. Because of the special tax arrangement, the sick leave balance may only go into the HRA account; it may not be taken as a cashout. The HRA program is administered by an independent third-party administrator, Meritain Health. HRA investments are managed by HRA Voluntary Employee Beneficiary Association (VEBA) Trust. The Department accrues all costs associated with compensated absences, including payroll taxes.

Use of Estimates—The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect amounts reported in the financial statements. The Department used significant estimates in determining reported allowance for doubtful accounts, unbilled revenues, power exchanges, accumulated provision for injuries and damages and workers' compensation, environmental liabilities, accrued sick leave, net pension liability, other postemployment benefits, and other contingencies. Actual results may differ from those estimates.

Significant Risk and Uncertainty—The Department is subject to certain business risks that could have a material impact on future operations and financial performance. These risks include financial market liquidity and economic uncertainty; prices on the wholesale markets for short-term power transactions; interest rates and other inputs and techniques for fair valuation; water conditions, weather, climate change, and natural disaster-related disruptions; terrorism; collective bargaining labor disputes; fish and other Endangered Species Act (ESA) issues; Environmental Protection Agency (EPA) regulations; compliance with clean and renewable energy legislation; local and federal government regulations or orders concerning the operations, maintenance, and/or licensing of hydroelectric facilities; other governmental regulations; restructuring of the electrical utility industry; and the costs of constructing transmission facilities that may be incurred as part of a northwest regional transmission system, and related effects of this system on transmission rights, transmission sales, surplus energy, and governance.

2. FAIR VALUE MEASUREMENT

The Department records certain assets, liabilities and deferred inflows of resources in accordance with GASB Statement No. 72, *Fair Value Measurement and Application*, which defines fair value, establishes a framework for measuring fair value, and requires disclosures about fair value measurement.

Fair value is defined in Statement No. 72 as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (an exit price). Fair value is a market-based measurement for a particular asset or liability based on assumptions that market participants would use in pricing the asset or liability. Such assumptions include observable and unobservable inputs of market data, as well as assumptions about risk and the risk inherent in the inputs to the valuation technique.

Valuation techniques to determine fair value should be consistent with one or more of three approaches: the market approach, cost approach, and income approach. The Department uses the market approach for the valuation of pooled investments, a combination of the market and income approaches for the valuation of the undelivered forward portion of energy exchanges and other nonmonetary transactions.

As a basis for considering market participant assumptions in fair value measurements, Statement No. 72 establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value into three broad levels as follows:

- Level 1 inputs are quoted prices (unadjusted) in active markets for identical assets or liabilities that the Department can access at the measurement date.

- Level 2 inputs are inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly or indirectly.

- Level 3 inputs are unobservable inputs for the asset or liability. Valuation adjustments such as for nonperformance risk or inactive markets could cause an instrument to be classified as Level 3 that would otherwise be classified as Level 1 or Level 2.

The valuation methods of the fair value measurements are disclosed as noted below.

Cash resources of the Department are combined with cash resources of the City to form a pool of cash and investments that is managed by the City's Department of Finance and Administrative Services (FAS). The City records pooled investments at fair value based on quoted market prices.

The Department obtained the lowest level of observable input of the fair value measurement of energy exchanges and other non-monetary transactions in its entirety from subscription services or other independent parties. The observable inputs for the settled portion of the energy exchange contracts are Dow Jones price indices. The observable inputs for the undelivered forward portion of energy exchanges and other non-monetary transactions are Kiodex forward curves and present value factors based on the interest rate for Treasury constant maturities, bond-equivalent yields.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Department's assessment of the significance of a particular input to the fair value measurement requires judgement and may affect the valuation of fair value assets and liabilities and their place within the fair value hierarchy levels.

The Department had no assets or liabilities that met the criteria for Level 3 at December 31, 2018 and 2017. The following fair value hierarchy table presents information about the Department's assets, liabilities, and deferred inflows of resources reported at fair value on a recurring basis or disclosed at fair value as of December 31, 2018 and 2017:

($ in millions)

2018	**Level 1**	**Level 2**	**Total**
Assets			
Fair value investments			
Bank note	$ 1.3	$ -	$ 1.3
Commercial paper	-	18.5	18.5
Municipal bonds	-	58.4	58.4
Repurchase agreements	17.7	-	17.7
U.S. government agency mortgage-backed securities	-	47.8	47.8
U.S. government agency securities	159.3	-	159.3
U.S. treasury & U.S. government-backed securities	72.6	-	72.6
Local government investment pool	-	23.2	23.2
Total fair value investments	250.9	147.9	398.8
Total Assets at fair value	$ 250.9	$ 147.9	$ 398.8

($ in millions)

2017 (Revised)	**Level 1**	**Level 2**	**Total**
Assets			
Fair value investments			
Bank note	$ -	$ 7.8	$ 7.8
Commercial paper	-	41.1	41.1
Municipal bonds	-	59.7	59.7
Repurchase agreements	22.6	-	22.6
U.S. government agency mortgage-backed securities	-	39.8	39.8
U.S. government agency securities	-	113.2	113.2
U.S. treasury & U.S. government-backed securities	75.6	2.0	77.6
Local government investment pool	-	19.7	19.7
Total fair value investments	98.2	283.3	381.5
Exchange energy receivable	-	1.6	1.6
Total Assets at fair value	$ 98.2	$ 284.9	$ 383.1
Deferred Inflows of Resources			
Exchange energy regulatory deferred gains	$ -	$ 0.8	$ 0.8

3. UTILITY PLANT

Utility Plant—Utility plant is recorded at original cost, which includes both direct costs of construction or acquisition and indirect costs, including an allowance for funds used during construction. The capitalization threshold for tangible assets was $5,000, and for intangible assets, $500,000 in 2018 and 2017. Plant constructed with capital contributions or contributions in-aid-of construction received from customers is included in Utility plant. Capital contributions and capital grants totaled $59.6 million in 2018 and $45.3 million in 2017. The Department uses a straight-line composite method of depreciation and amortization and, therefore, groups assets into composite groups for purposes of depreciation. Estimated economic lives range from 4 to 50 years. Effective with the implementation of a new fixed asset system January 1, 2017, the Department changed from a half-year convention method of depreciation to an actual month method, on the assumption that additions and replacements are placed in service at mid-year. Depreciation and amortization expense as a percentage of depreciable utility plant-in-service was approximately 2.4% in 2018 and 2.8% in 2017. When operating plant assets are retired, their original cost together with retirement costs and removal costs, less salvage, is charged to accumulated depreciation or amortization, if applicable. The cost of maintenance and repairs is charged to expense as incurred, while the cost of replacements and betterments are capitalized. The Department periodically reviews long-lived assets for impairment to determine whether any events or circumstances indicate the carrying value of the assets may not be recoverable over their economic lives.

Intangible assets are those that lack physical substance, are nonfinancial in nature, and have useful lives extending beyond a single reporting period. The Department's intangible assets are reported as capital assets under Utility Plant. The Department's intangible assets consist of easements, purchased and internally developed software, transmission rights, capitalized relicensing costs for Skagit and Boundary hydroelectric projects, Tolt hydroelectric project mitigation costs, and costs capitalized under the High Ross Agreement.

Utility plant-in-service at original cost, including land at December 31, 2018, and 2017, was:

2018 ($ in millions)	Hydroelectric Production	Transmission	Distribution	General	Intangibles	Total
Utility Plant-in-service - At original cost:						
Plant-in-service, excluding Land:						
1/1/2018 Balance	$ 863.6	$ 266.6	$ 2,500.7	$ 384.4	$ 577.9	$ 4,593.2
Acquisitions	38.5	27.5	339.4	14.6	86.5	506.5
Dispositions	(5.7)	(3.5)	(29.6)	(7.1)	-	(45.9)
Transfers and adjustments	-	-	3.9	-	-	3.9
	896.4	290.6	2,814.4	391.9	664.4	5,057.7
Accumulated depreciation and amortization:						
1/1/2018 Balance	$ 370.4	$ 87.2	$ 927.5	$ 235.6	$ 202.7	$ 1,823.4
Increase in accumulated depreciation and amortization	15.2	6.0	72.8	12.2	23.2	129.4
Retirements	(8.8)	(5.8)	(43.0)	(7.1)	-	(64.7)
Transfers and adjustments	1.0	1.1	3.6	-	-	5.7
12/31/2018 Balance	377.8	88.5	960.9	240.7	225.9	1,893.8
Sub Total Plant-in-service - Net, excluding Land:	$ 518.6	$ 202.1	$ 1,853.5	$ 151.2	$ 438.5	$ 3,163.9
Land and land rights:						
1/1/2018 Balance	$ 53.6	$ 3.0	$ 13.4	$ 6.6	$ -	$ 76.6
Acquisitions	0.9	-	72.7	-	-	73.6
Dispositions	-	-	-	-	-	-
Transfers and adjustments	-	-	-	-	-	-
12/31/2018 Balance	54.5	3.0	86.1	6.6	-	150.2
Total Plant-in-service - Net, including Land:	$ 573.1	$ 205.1	$ 1,939.6	$ 157.8	$ 438.5	$ 3,314.1

2017 ($ in millions)	Hydroelectric Production	Transmission	Distribution	General	Intangible	Total
Utility Plant-in-service - At original cost:						
Plant-in-service, excluding Land:						
1/1/2017 Balance	$ 847.0	$ 242.2	$ 2,408.9	$ 368.4	$ 543.8	$ 4,410.3
Acquisitions	22.9	27.1	110.8	28.1	34.1	223.0
Dispositions	(6.3)	(2.7)	(24.2)	(12.1)	-	(45.3)
Transfers and adjustments	-	-	5.2	-	-	5.2
12/31/2017 Balance	863.6	266.6	2,500.7	384.4	577.9	4,593.2
Accumulated depreciation and amortization:						
1/1/2017 Balance	361.0	85.2	881.5	230.6	177.0	1,735.3
Increase in accumulated depreciation and amortization	16.7	5.8	73.8	18.2	24.6	139.1
Retirements	(7.3)	(3.8)	(27.8)	(12.1)	-	(51.0)
Transfers and adjustments	-	-	-	(1.1)	1.1	-
12/31/2017 Balance	370.4	87.2	927.5	235.6	202.7	1,823.4
Sub Total Plant-in-service - Net: excluding Land:	$ 493.2	$ 179.4	$ 1,573.2	$ 148.8	$ 375.2	$ 2,769.8
Land and land rights:						
1/1/2017 Balance	$ 52.0	$ 3.0	$ 13.4	$ 6.6	$ -	$ 75.0
Acquisitions	0.7	-	-	-	-	0.7
Dispositions	-	-	-	-	-	-
Transfers and adjustments	0.9	-	-	-	-	0.9
12/31/2017 Balance	53.6	3.0	13.4	6.6	-	76.6
Total Plant-in-service - Net: including Land:	$ 546.8	$ 182.4	$ 1,586.6	$ 155.4	$ 375.2	$ 2,846.4

4. RATE STABILIZATION ACCOUNT

The Rate Stabilization Account (RSA) is a restricted cash reserve established to reduce the need for rapid and substantial rate increases solely to comply with the Department's bond covenants.

In March 2010, the Seattle City Council adopted Resolution No. 31187 and Ordinance No. 123260, establishing revised financial policies and parameters for the operation of the RSA created by Ordinance No. 121637 in 2004. Ordinance No. 123260 identified the sources of significant funding of the RSA and specified parameters for its operation. The RSA is drawn down to supplement revenues when surplus power sales revenues are below the budgeted amount, and conversely, deposits are to be made to the RSA when the surplus power sales revenues are greater than budgeted. Deposits or withdrawals may be made up to and including the date 90 days after the end of the applicable year.

Ordinance No. 123260 established a target size for the RSA of no less than $100.0 million and no greater than $125.0 million, and authorized the imposition of automatic temporary surcharges on electric rates when the RSA balance is within the below specified levels:

RSA Balance	Action
Less than or equal to $90.0 million but greater than $80.0 million:	Automatic 1.5% surcharge
Less than or equal to $80.0 million but greater than $70.0 million:	Automatic 3.0% surcharge
Less than or equal to $70.0 million but greater than $50.0 million:	Automatic 4.5% surcharge
Less than or equal to $50.0 million:	City Council must initiate rate review within 45 days and determine actions to replenish RSA to $100.0 million within 12 months

In February 2014, the Seattle City Council adopted Ordinance No. 124426 (retroactive to December 2013), directing specific cash transfers to the RSA with the intention of reducing the likelihood of future rate surcharges.

Ordinance No. 123260 originally required a rate review whenever the RSA balance exceeded $125.0 million, along with the implementation of measures to reduce the RSA balance to $125.0 million within a period of 12 months or less. Subsequently, the Seattle City Council adopted Ordinance No. 124108 in February 2013 (retroactive to January 1, 2013) which extended the timing of this required rate review and associated action to an effective date of January 1, 2014.

In 2018, actual net wholesale revenue was $9.9 million less than budgeted. Hence, net transfers of $9.9 million were made from the RSA to the operating cash account during the year. The 1.5% surcharge enacted August 1, 2016 remained in effect throughout 2018. Transfers from the RSA were fully offset by $11.6 million surcharge revenue resulting from the 1.5% surcharge. Interest of $1.8 million was earned on the RSA in 2018. The RSA ending balance was $96.9 million at December 31, 2018.

In 2017, actual net wholesale revenue was $10.3 million less than budgeted. Hence, net transfers of $10.3 million were made from the RSA to the operating cash account during the year. The 1.5% surcharge enacted August 1, 2016 remained in effect throughout 2017. Transfers from the RSA were fully offset by $11.2 million surcharge revenue resulting from the 1.5% surcharge. Interest of $1.4 million was earned on the RSA in 2017. The RSA ending balance was $93.4 million at December 31, 2017.

The RSA at December 31, 2018, and 2017, consisted of cash from the following sources:

($ in millions)	2018	2017
Rate Stabilization Account		
Beginning balance	$ 93.4	$ 91.1
Surcharge revenue	11.6	11.2
RSA interest income	1.8	1.4
Operating revenue	(9.9)	(10.3)
Ending balance	$ 96.9	$ 93.4

RSA transactions are recorded in accordance with GASB Statement No. 62 *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements*.

The regulatory deferred inflow of resources rate stabilization unearned revenue account at December 31, 2018, and 2017, consisted of the following:

($ in millions)	2018	2017
Unearned revenue - Rate Stabilization Account		
Beginning balance	$ 68.4	$ 66.1
Surcharge revenue	11.6	11.2
RSA interest income	1.8	1.4
Operating revenue	(9.9)	(10.3)
Ending balance	$ 71.9	$ 68.4

The initial $25.0 million transfer from the Contingency Reserve Account to the RSA in May 2010 is not included in the Rate stabilization unearned revenue balance and is not available to be transferred to current revenue in the event that net wholesale revenues are less than the budgeted amount. The Contingency Reserve Account was established in 2005 with proceeds that had been deposited in the Bond Reserve Fund, which was replaced with a surety bond.

Net transfers from/(to) the RSA in the statements of revenues, expenses and net position for the periods ended December 31, 2018, and 2017 were as follows:

($ in millions)	2018	2017
Transfers from/(to) Rate Stabilization Account	$ (3.5)	$ (2.3)

5. CASH AND EQUITY IN POOLED INVESTMENTS AND INVESTMENTS

Cash and Equity in Pooled Investments—Cash resources of the Department are combined with cash resources of the City to form a pool of cash that is managed by the City's Department of Finance and Administrative Services (FAS). Under the City's investment policy, all temporary cash surpluses in the pool are invested. The Department's share of the pool is included on the balance sheets as Cash and Equity in Pooled Investments or as restricted assets. The pool operates like a demand deposit account in that all departments, including the Department, may deposit cash at any time and can also withdraw cash, out of the pool, up to the amount of the Department's fund balance, without prior notice or penalty. Accordingly, the statements of cash flows reconcile to cash and equity in pooled investments. The City considers investments in financial instruments having a maturity of 90 days or less as a cash equivalent.

Custodial Credit Risk – Deposits—Custodial credit risk of deposits is the risk that in the event of bank failure for one of the City's depository institutions, the City's deposits or related collateral securities may not be returned in a timely manner.

As of December 31, 2018, and 2017, the City did not have custodial credit risk. The City's deposits are covered by insurance provided by the Federal Deposit Insurance Corporation (FDIC) and the National Credit Union Association (NCUA) as well as protection provided by the Washington State Public Deposit Protection Commission (PDPC) as established in RCW 39.58. The PDPC makes and enforces regulations and administers a program to ensure public funds deposited in banks and thrifts are protected if a financial institution becomes insolvent. The PDPC approves which banks, credit unions, and thrifts can hold state and local government deposits and monitors collateral pledged to secure uninsured public deposits. This secures public treasurers' deposits when they exceed the amount insured by the FDIC or NCUA by requiring banks, credit unions, and thrifts to pledge securities as collateral.

As of December 31, 2018, and 2017, the City held $95,000 in its cash vault. Additional small amounts of cash were held in departmental revolving fund accounts with the City's various custodial banks, all of which fell within the NCUA/FDIC's $250,000 standard maximum deposit insurance amount. Any of the City's cash not held in its vault, or a local depository, was held in the City's operating fund (investment pool), and at the close of every business day, any cash remaining in the operating fund is swept into an overnight repurchase agreement that matures the next day.

Investments—The Department's cash resources may be invested by FAS separate from the cash and investments pool. Investments are managed in accordance with the City's Statement of Investment Policy, with limits and restrictions applied at the City-wide level rather than to specific investments of the Department. As of December 31, 2018, and 2017, the Department did not have any dedicated investments. The City's Statement of Investment Policy was modified on January 1, 2018, with an effective date of March 8, 2018 and includes, but is not limited to, the topics of Standards of Care, Objectives, Strategy, Eligible Investments and Investment Parameters.

The City follows a set of Standards of Care when it comes to its investments that include the following:

- Social Policies: A City social policy shall take precedence over furthering the City's financial objectives when expressly authorized by City Council resolution, except where otherwise provided by law or trust principles.

- Prudence: The standard of prudence to be used by investment personnel shall be the "Prudent Investor Rule" and will be applied in the context of managing an overall portfolio.

- Ethics and Conflict of Interest: Investment officers shall comply with the City's Ethics Code (SMC 4.16.080) and annually submit a Financial Interest Statement to the City's Ethics & Elections Commission that identifies any potential financial interest that could be related to the performance of the City's investment portfolio.

- Delegation of Authority: The Director of Finance and Administrative Services has delegated management responsibility for the City's investment program to the Director of Finance who has designated day to day management responsibility to investment officers under the supervision of the City's Treasury Services Director. No persons may engage in an investment transaction except as provided under the terms of the City Statement of Investment Policy and the procedures established therein.

The three objectives in managing the City of Seattle's investments define its risk profile and guide implementation of its investment strategy. In order of importance they are Safety of Principal, Maintenance of Liquidity, and Return on Investment.

Eligible investments for the City are those securities and deposits authorized by statute (RCW 39.59.040) and include, but are not limited to:

A. Bonds of the state of Washington and any local government in the state of Washington;

B. General obligation bonds of a state and general obligation bonds of a local government of a state, which bonds have at the time of investment one of the three highest credit ratings of a nationally recognized rating agency;

C. Subject to compliance with RCW 39.56.030, registered warrants of a local government in the same county as the government making the investment;

D. Certificates, notes, or bonds of the United States, or other obligations of the United States or its agencies, or of any corporation wholly owned by the government of the United States;

E. United States dollar denominated bonds, notes, or other obligations that are issued or guaranteed by supranational institutions, provided that at the time of investment, the institution has the United States government as its largest shareholder;

F. Federal home loan bank notes and bonds, federal land bank bonds and federal national mortgage association notes, debentures, and guaranteed certificates of participation, or the obligations of any other government sponsored corporation whose obligations are or may become eligible as collateral for advances to member banks as determined by the board of governors of the federal reserve system;

G. Bankers' acceptances purchased in the secondary market;

H. Commercial paper purchased in the secondary market;

I. Corporate notes purchased in the secondary market.

State statute also permits investment in the following types of securities:

A. Certificates of deposit or demand deposits with financial institutions made in accordance with the provisions of Chapter 39.58 RCW;

B. Washington State Local Government Investment Pool (LGIP), Chapter 43.250 RCW;

C. Repurchase agreements collateralized by the above eligible securities issued by the U.S. Government and its sponsored entities.

As of December 31, 2018, and 2017, the City's pooled investments were as follows:

($ in millions)	2018		2017	
	Fair Value of City Pooled Investments	**Weighted-Average Maturity (Days)**	**Fair Value of City Pooled Investments**	**Weighted-Average Maturity (Days)**
Bank Note	$ 8.1	22	$ 48.0	294
Commercial Paper	114.5	14	251.7	33
Local Government Investment Pool	143.7	1	120.7	1
Municipal Bonds	361.3	1954	366.1	1858
Repurchase Agreements	109.4	2	138.4	2
Agency Mortgage Backed Securities	295.8	1872	243.7	1732
US Government Agency Securities	986.1	1367	693.6	1209
US Treasury Bonds	449.7	840	475.7	490
Total	$ 2,468.6		$ 2,337.9	
Portfolio Weighted Average Maturity		867		803

As of December 31, 2018, and 2017, the Department's share of the City pool was as follows:

($ in millions)	**2018**	**2017**
Operating cash and equity in pooled investments	$ 135.1	$ 129.1
Restricted cash and equity in pooled investments	263.7	252.4
Total	$ 398.8	$ 381.5
Balance as a percentage of City pool cash and investments	16.2%	16.3%

Fair Value of Pooled Investments—The City reports investments at fair value and categorizes its fair value measurements within the fair value hierarchy established by GASB Statement No. 72, *Fair Value Measurement and Application*. See Note 2 Fair Value Measurement. Fair value of the City's pooled investments fluctuates with changes in interest rates and the underlying size of the pooled investment portfolio. To mitigate interest rate risk in the City's pooled investment portfolio, the City typically holds its investments to maturity and manages its maturities to ensure sufficient monthly cash flow to meet its liquidity requirements. During the first quarter of 2019, yields for U.S. Treasuries declined while the yield curve between short and long-term debt inverted more extensively. At the conclusion of the Federal Open Market Committee meeting in March 2019, the Federal Reserve left its range for the federal funds target unchanged at 2.25% - 2.50%. The Federal Reserve announced it does not expect to raise interest rates during 2019 given a dour outlook for the U.S. economy. Lower interest rates will reduce the unrealized loss on the City's investments and may potentially turn the position to an unrealized gain. New investments are anticipated to be lower yielding.

The City holds a $143.7 million deposit in the Washington State Local Government Investment Pool (LGIP) managed by the Office of the Washington State Treasurer. The City's investments in the LGIP are reported at amortized cost which approximates fair value. It is overseen by the Office of the State Treasurer, the State Finance Committee, the Local Government Investment Pool Advisory Committee, and the Washington State Auditor's Office.

To provide for the City's investment objectives, parameters have been established that guide the investment officers. Management of the Pool is subject to the restrictions outlined in the following sections.

Interest Rate Risk—Interest rate risk is the risk that changes in interest rates over time will adversely affect the fair value of an investment. To mitigate interest rate risk, the City intentionally immunizes its known and expected cash flow needs. To best accomplish meeting its investment objectives, the City has divided the Pool into two separate portfolios: Operating and Strategic.

The Operating Portfolio is invested to meet reasonably expected liquidity needs over a period of twelve to eighteen months. This portfolio has low duration and high liquidity. Consistent with this profile, and for the purpose of comparing earnings yield, its benchmark is the net earnings rate of the State of Washington's Local Government Investment Pool (LGIP).

The Strategic Portfolio consists of cash that is in excess of known and expected liquidity needs. Accordingly, this portfolio is invested in debt securities with longer maturities than the Operating Portfolio, which over a market cycle, is expected to provide a higher return and greater investment income. Consistent with this profile, and for the purpose of comparing duration, yield and total return, the benchmark for the Strategic portfolio is the Barclays U.S. Government 1-7 year index. The duration of the Strategic Portfolio is targeted between 75 percent and 125 percent of the benchmark.

To further mitigate interest rate risk a minimum of 60% of the Operating Portfolio and 30% of the Strategic Portfolio must be invested in asset types with high liquidity, specifically U.S. government obligations, U.S. government agency obligations, LGIP, demand accounts, repo, sweep, commercial paper and Banker's Acceptances.

Credit Risk—Credit risk is the risk that an issuer or other counterparty to an investment will not fulfill its obligations.

To mitigate credit risk, municipal bonds must have one of the three highest credit ratings of a Nationally Recognized Statistical Rating Agency (NRSRO) at the time of purchase. The Office of the State Treasurer interprets the three highest credit ratings to include AAA, AA and A including gradations within each category. For example, the lowest credit rating allowable is A3 by Moody's and A- by S&P and Fitch.

Commercial paper and corporate note investments must adhere to the Washington State Investment Board Policy Number 2.05.500, and together are defined as the "credit portfolio" with the following constraints in place to mitigate credit risk:

Commercial paper investments may not have maturities exceeding 270 days and must hold the highest short-term credit rating by all the major credit rating agencies that rate the issuer at the time of purchase.

Corporate notes must be rated at least weak single-A or better by all the major rating agencies that rate the note at the time of purchase. Corporate notes rated in the broad single-A category with a negative outlook may not be purchased. Portfolio holdings of corporate notes downgraded to below single A and portfolio holdings of securities rated single A with their outlooks changed to negative may continue to be held. No additional purchases are permitted.

Municipal bonds must have a credit rating of weak single-A or better by all the major rating agencies that rate the issuer at the time of purchase. No single issuer may exceed 5 percent of the Pool's market value.

Concentration Risk—Concentration Risk is the risk of loss attributed to the magnitude of investments in a single issuer. The City manages concentration risk by limiting its investments in any one issuer in accordance with the City's investment policy and state statutes. The policy limits vary for each investment category.

The maturity of a corporate note shall be 5.5 years or less at the time of purchase. The maximum duration of aggregate corporate note investments shall not exceed 3 years. No corporate note issuer may exceed 3 percent of the market value of the assets of the total portfolio. The percentage of corporate notes that may be purchased from any single issuer rated AA or better by all major rating agencies that rate the note is 3 percent of assets of the total portfolio. The percentage of corporate notes that may be purchased from any single issuer in the broad single-A category from all the major rating agencies that rate the security is 2 percent of the total portfolio.

The credit portfolio may not exceed 25 percent of the Pool's market value. Credit investments must be diversified by sector and industry. Commercial paper and corporate notes must be purchased in the secondary market and directly from an issuer. No single issuer shall exceed 3 percent of the total portfolio's market value.

The individual country limit of non-U.S. and non-Canadian exposure is 2 percent of the total portfolio. The exposure is determined by the country of domicile of the issuer.

State statute and the City's Statement of Investment Policy do not stipulate concentration limits for holdings of U.S. Government or U.S. Government Agency Obligations. There is a maximum of 5 percent of the Pool in any municipal issuer. The City's investments in which 5% or more is invested in any single issuer as of December 31, 2018 and 2017 are as follows:

($ in millions)	2018		2017	
Issuer	**Fair Value**	**Percent of Total Investments**	**Fair Value**	**Percent of Total Investments**
Federal Farm Credit Bank/Federal Home Loan Bank	$ 656.9	27%	$ 428.9	18%
Municipal Bonds	361.3	15%	366.1	16%
Federal National Mortgage Association	234.7	10%	291.7	12%
United States Treasury (HUD Debenture, US Treasury Bonds)	449.7	18%	475.7	20%
Federal Home Loan Mortgage Corp. and FHMS K Series	234.3	9%	146.5	6%
Local Government Investment Pool	143.7	6%	120.7	5%
SWEEP-REPO	109.4	4%	138.4	6%
	$ 2,190.0	89%	$ 1,968.0	83%

Custodial Credit Risk – Investments—Custodial credit risk for investments is the risk that, in the event of failure of the counterparty, the City will not have access to, or be able to recover, its investments or collateral securities that are in the possession of an outside party. The City mitigates custodial credit risk for its investments by having its investment securities held by the City's contractual custodial agent. The City maintains a custody relationship with Wells Fargo under the State of Washington's statewide custody provider program arranged by the State Treasurer's Office. The City mitigates counterparty risk by settling trades through its custodian on a delivery-versus-payment method.

By investment policy, the City maintains a list of approved securities dealers for transacting business. The City also conducts its own due diligence as to the financial wherewithal of its counterparties.

Foreign Currency Risk—The City's pooled investments do not include securities denominated in foreign currencies.

The City of Seattle's Comprehensive Annual Financial Report may be obtained by writing to The City of Seattle, Department of Finance and Administrative Services, P.O. Box 94689, Seattle, WA 98124-4689; telephone: (206) 684-2489, or obtained on-line at http:/www.seattle.gov/financial-services/comprehensive-annual-financial-report.

6. ACCOUNTS RECEIVABLE

Accounts receivable at December 31, 2018 and 2017, consist of:

($ in millions)	Retail Electric	Wholesale Power	Other Operating	Operating Subtotal	Nonoperating Subtotal	Total
2018						
Accounts receivable	$ 95.3	$ 9.0	$ 17.4	$ 121.7	$ 46.1	$ 167.8
Less allowance for doubtful accounts	(32.4)	-	(12.8)	(45.2)	-	(45.2)
	$ 62.9	$ 9.0	$ 4.6	$ 76.5	$ 46.1	$ 122.6
2017						
Accounts receivable	$ 62.5	$ 9.7	$ 15.2	$ 87.4	$ 22.9	$ 110.3
Less allowance for doubtful accounts	(12.7)	-	(8.8)	(21.5)	-	(21.5)
	$ 49.8	$ 9.7	$ 6.4	$ 65.9	$ 22.9	$ 88.8

Wholesale power receivable includes $ - million at December 31, 2018, and $1.6 million at December 31, 2017, for exchange energy at fair value under long-term contracts (see Note 19 Long-Term Purchased Power, Exchanges, and Transmission).

7. OTHER ASSETS

Seattle City Council passed resolutions authorizing debt financing and reporting as regulatory assets certain costs in accordance with Statement No. 62 of the GASB, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements*. Programmatic conservation costs incurred by the Department and not funded by third parties, Endangered Species Act costs, and environmental costs are reported as regulatory assets in accordance with GASB Statement No. 62. Conservation costs reported as regulatory assets are amortized over 20 years. Endangered Species Act costs reported as regulatory assets are amortized over the remaining license period (see Note 19 Commitments and Contingencies). Environmental costs reported as regulatory assets are amortized over 25 years, beginning in the year costs are paid.

Other assets, which are not covered under GASB Statement No. 62, consist of:

- Suburban infrastructure long-term receivables are underground electrical infrastructure costs for suburban jurisdictions, which are recovered through rates from customers within the respective jurisdictions for a period of approximately 25 years, as approved by the Seattle City Council.

- Long-term interfund receivable for expected recoveries related to environmental costs covered under GASB Statement No. 49, *Accounting and Financial Reporting for Pollution Remediation Obligations* (see Note 15 Environmental Liabilities).

- Puget Sound Energy interconnection and substation costs are being amortized to expense over 25 years.

- Studies, surveys, and investigations are reported as other assets until such time they result in active projects, or when it is determined no assets will result, at which time they are expensed.

- Long-term customer loans receivable and the remaining components of other assets, are not amortized.

Regulatory assets and other assets, net, at December 31, 2018 and 2017, consisted of the following:

($ in millions)	2018	2017
Regulatory assets:		
Conservation costs—net	$ 261.5	$ 262.2
Endangered Species Act costs—net	1.6	1.8
Environmental costs	113.7	93.1
	376.8	357.1
Other charges and assets—net:		
Suburban infrastructure long-term receivables	50.8	51.7
Long-term interfund receivable for environmental costs	0.3	3.8
Long-term customer notes receivable	0.6	0.4
Puget Sound Energy interconnection and substation	0.2	0.3
Studies, surveys, and investigations	2.8	2.8
Other	0.5	0.7
	55.2	59.7
Total Other Assets	$ 432.0	$ 416.8

8. DEFERRED OUTFLOWS OF RESOURCES

In accordance with the requirements of GASB Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27* and Statement No. 71, *Pension Transition for Contributions Made Subsequent to the Measurement Date – an amendment of GASB Statement No. 68,* the Department recognizes pension contributions made between the pension plan measurement date and the Department's fiscal year end as deferred outflows of resources. Also recognized as deferred outflows of resources are losses resulting from differences between projected and actual earnings on plan investments, which are amortized over a closed five-year period, and losses related to differences between expected and actual experience with regard to economic or demographic factors in the measurement of total pension liability, which are amortized to pension expense over a period equal to the expected remaining service life of employees receiving pension benefits. See Note 13 Seattle City Employees' Retirement System.

On January 1, 2018, City Light implemented GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions (OPEB)*, which concerns the accounting for and disclosure of other postemployment benefits. According to this GASB the Department records the contributions subsequent to the net OPEB liability measurement date, but before the end of the reporting period, as deferred outflows of resources. Also, the deferred outflows of resources result from (1) differences between expected and actual experience, (2) changes in assumptions, and (3) differences between projected and actual investment earnings. Deferred outflows of resources from assumption changes and experience differences are amortized using a systematic and rational method over a closed period equal to the average remaining service lives of all plan participants. Deferred outflows from investment earnings differences are amortized over a closed five-year period. See Note 14 Other Postemployment Benefits.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt are reported as Deferred outflows of resources and amortized as a component of interest expense using the effective interest method over the terms of the issues to which they pertain. See Note 9 Long-term Debt.

Deferred outflows of resources at December 31, 2018 and 2017 consisted of the following:

($ in millions)	2018	2017
Deferred outflows of resources:		
Unrealized contributions and losses related to pension	$ 24.8	$ 46.9
Unrealized contributions and losses related to OPEB	2.1	-
Charges on advance refunding	31.0	36.3
Total	$ 57.9	$ 83.2

9. LONG-TERM DEBT

At December 31, 2018 and 2017, the Department's long-term debt consisted of the following prior lien or parity bonds:

LONG-TERM *($ in millions)*		Rate	Maturity Year	Original Issuance	2018	2017
Prior Lien Bonds:						
2018C2	ML&P Refunding Revenue Bonds	variable rates	2046	$ 49.2	$ 48.6	-
2018C1	ML&P Refunding Revenue Bonds	variable rates	2046	49.2	48.6	-
2018B2	ML&P Refunding Revenue Bonds	variable rates	2045	50.1	50.1	-
2018B1	ML&P Refunding Revenue Bonds	variable rates	2045	50.1	50.1	-
2018A	ML&P Improvement Revenue Bonds	4.000%–5.000%	2048	263.8	263.8	-
2017C	ML&P Improvement and Refunding Revenue Bonds	4.000%–5.000%	2047	385.5	380.4	385.5
2017A	ML&P Revenue Bonds	variable rates	2046	50.0	-	49.1
2017B	ML&P Revenue Bonds	variable rates	2046	50.0	-	49.1
2016A	ML&P Revenue Bonds	4.050% fixed	2041	31.9	31.9	31.9
2016B	ML&P Refunding Revenue Bonds	4.000%–5.000%	2029	116.9	115.3	115.3
2016C	ML&P Improvement and Refunding Revenue Bonds	4.000%–5.000%	2046	160.8	156.5	158.7
2015A	ML&P Revenue Bonds	4.000%–5.000%	2045	171.9	155.0	161.1
2015B1	ML&P Adjustable Rate Revenue Bonds	variable rates	2045	50.0	-	50.0
2015B2	ML&P Adjustable Rate Revenue Bonds	variable rates	2045	50.0	-	50.0
2014	ML&P Improvement and Refunding Revenue Bonds	4.000%–5.000%	2044	265.2	216.4	232.2
2013	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2043	190.8	175.4	178.7
2012A	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2041	293.3	225.8	243.9
2012C	ML&P Clean Renewable Energy Bonds	3.400%–3.750%	2033	43.0	43.0	43.0
2011A	ML&P Improvement and Refunding Revenue Bonds	1.000%–5.500%	2036	296.3	69.3	80.7
2011B	ML&P Clean Renewable Energy Bonds	5.750%–5.750%	2027	10.0	10.0	10.0
2010A	ML&P Build America Bonds	4.447%–5.570%	2040	181.6	181.6	181.6
2010B	ML&P Improvement and Refunding Revenue Bonds	2.000%–5.000%	2026	596.9	246.5	290.3
2010C	ML&P Recovery Zone Economic Development Bonds	5.590%–5.590%	2040	13.3	13.3	13.3
2008	ML&P Revenue and Refunding Revenue Bonds	4.000%–6.000%	2029	257.4	10.0	21.1
Total prior lien bonds				$ 3,677.2	$ 2,491.6	$ 2,345.5

The Department had the following activity in long-term debt during 2018 and 2017:

($ in millions)	Balance at 1/1/18	Additions	Reductions	Balance at 12/31/18	Current Portion
2018					
Prior Lien Bonds - fixed rate	$ 2,147.3	$ 263.8	$ (117.0)	$ 2,294.1	$ 116.5
Prior Lien Bonds - variable rate	198.2	198.8	(199.5)	197.5	2.9
	$ 2,345.5	$ 462.6	$ (316.5)	$ 2,491.6	$ 119.4

($ in millions)	Balance at 1/1/17	Additions	Reductions	Balance at 12/31/17	Current Portion
2017					
Prior Lien Bonds - fixed rate	$ 2,018.1	$ 385.5	$ (256.3)	$ 2,147.3	$ 117.0
Prior Lien Bonds - variable rate	100.0	100.0	(1.8)	198.2	1.8
	$ 2,118.1	$ 485.5	$ (258.1)	$ 2,345.5	$ 118.8

Prior Lien Bonds—In June 2018, the Department issued $263.7 million of tax exempt Municipal Light and Power (ML&P) Improvement Revenue Bonds (2018A Bonds) and in September 2018 issued $100.3 million of tax exempt variable rate Municipal Light and Power (ML&P) Revenue Refunding Revenue Bonds (2018B Bonds) and $98.5 million of tax exempt Municipal Light and Power (ML&P) Revenue Refunding Bonds (2018C Bonds). The 2018A Bonds had coupon interest rates ranging from 4.00% to 5.00% and mature serially from January 1, 2019 through January 1, 2048. The 2018B term Bonds had coupon interest rates ranging from 1.77% to 2.00% during 2018 with term bonds Bonds maturing May 1, 2045. The 2018C Bonds had coupon interest rates ranging from 1.63% to 2.20% during 2018 and mature serially from November 1, 2020 to November 1, 2023 with term bonds maturing annually from November 1, 2018 to November 1, 2046. The 2018B&C Bonds bear interest at the adjusted Securities Industry and Financial Markets Association (SIFMA) interest rate which is the SIFMA index plus the Index floating rate spread. The arbitrage yield was 3.15% for the 2018A Bonds and 3.38% for the 2018B and 2018C Bonds. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the Bonds in the manner prescribed by the Internal Revenue Code, produces an amount equal to the issue price of the Bonds. Proceeds from the 2018A Bonds were used to finance certain capital improvement and conservation programs and to make a deposit to the reserve fund. Proceeds from the 2018B&C Bonds were used to refund $100.0 million of the 2015B Bonds and $98.2 million of the 2017A&B Bonds.

The debt service on the 2018A Bonds requires a cash flow over the life of the bonds of $458.9 million, including $195.1 million in interest, the debt service on the 2018B Bonds requires a cash flow over the life of the bonds of $172.4 million, including $72.1 million in interest, and the debt service on the 2018C Bonds requires a cash flow over the life of the bonds of $162.5 million, including $64.0 million in interest. The 2018B and 2018C Bonds refunded the 2015B and 2017A&B Bonds on a current basis and there was no savings or accounting gain or loss on the refunding. Refunding on a current basis is a refunding transaction where the municipal securities being refunded will all mature or be redeemed within 90 days or less from the date of issuance of the refunding issue.

In January 2017 the Department issued $100.0 million of tax exempt Municipal Light and Power (ML&P) Multi-Modal Revenue Bonds (2017A&B Bonds) and in September 2017 issued $385.5 million of tax exempt Municipal Light and Power (ML&P) Improvement and Refunding Revenue Bonds (2017C Bonds). The 2017A&B Bonds had coupon interest rates ranging from .97% to 1.38% during 2017 and mature serially from November 1, 2017 to November 1, 2046. The 2017A&B Multi-Modal Bonds bear interest rates at variable rates that fluctuate based on the London Interbank Offered Rate (LIBOR) plus a certain number of basis points. The 2017C Bonds had coupon interest rates ranging from 4.00% to 5.00% and mature serially from September 1, 2018 through September 1, 2043 with term bonds maturing annually from September 1, 2044 to September 1, 2047. The arbitrage yield was 4.033% for the 2017A&B Bonds and 2.63% for the 2017C Bonds. Arbitrage yield, when used in computing the present worth of all payments of principal and interest on the Bonds in the manner prescribed by the Internal Revenue Code, produces an amount equal to the issue price of the Bonds. Proceeds from the 2017A&B Bonds were used to finance certain capital improvement and conservation programs. Proceeds from the 2017C Bonds were used to refund $145.1 million of the 2011A Bonds, to finance certain capital improvement and conservation programs, and to make a deposit to the reserve fund.

The debt service on the 2017A&B Bonds requires a cash flow over the life of the bonds of $172.6 million, including $72.6 million in interest, and the debt service on the 2017C Bonds requires a cash flow over the life of the bonds of $656.7 million, including $271.2 million in interest. The difference between the cash flows required to service the old and new debt and to complete the refunding for the 2017C Bonds totaled $21.5 million and the aggregate economic gain on refunding totaled $18.9 million at present value. The accounting loss on refunding for the 2017C Bonds was $11.0 million.

The Department has certain bonds outstanding that provide a refundable tax credit, or federal subsidy, paid to state or local governmental issuers by the U.S. Treasury. The amount of the federal subsidy is equal to the lesser of the amount of interest payable based on the coupon interest rate or a percentage of the amount of interest payable based on the tax credit rate on the sale date with respect to those bonds. This federal subsidy ultimately results in a net decrease to debt service, although debt service payments are paid gross. The federal subsidies are recorded as nonoperating revenues on the statements of revenues, expenses, and changes in net position.

Federal Sequestration—The sequestration provisions of the Budget Control Act of 2011 went into effect on March 1, 2013. The only direct impact of sequestration on the Department for 2018 was a 6.6% reduction through the end of the federal fiscal year (FFY) ending September 30, 2018 at which time the automatic reductions were adjusted to 6.2% in the amount the Department expects to receive from the federal government in connection with its Municipal Light and Power Revenue Bonds, 2010A (Taxable Build America Bonds—Direct Payment); Municipal Light and Power Revenue Bonds, 2010C (Taxable Recovery Zone Economic Development Bonds—Direct Payment); Municipal Light and Power Improvement Revenue Bonds, 2011B (Taxable New Clean Renewable Energy Bonds—Direct Payment); Municipal Light and Power Improvement Revenue Bonds, 2012C (Taxable New Clean Renewable Energy Bonds—Direct Payment); and Municipal Light and Power Revenue Bonds, 2016A (Taxable New Clean Renewable Energy Bonds—Direct Payment). Because of this reduction, the Department received $0.4 million less in interest subsidies than originally anticipated for 2018. The Department has sufficient revenues to pay the interest without these subsidies. The effect for the accrual of federal subsidies as of December 31, 2018 was inconsequential. The effect during 2019 is estimated to be lower federal subsidies by approximately $0.4 million. The effect thereafter for federal subsidies is indeterminable. Sequestration was originally in effect through FFY 2021 and has subsequently been extended through FFY 2024.

Debt service requirements for prior lien bonds, excluding federal subsidies for the 2016, 2012, 2011 and 2010 bonds are shown in the table below. Future debt service requirements on the variable 2018B and 2018C Bonds are estimated based on actual interest rates in effect as of December 31, 2018.

($ in millions)

	Fixed Rate Bonds		Variable Rate Bonds		
Years Ending December 31	**Principal Redemptions**	**Interest Requirements**	**Principal Redemptions**	**Interest Requirements**	**Total**
2019	$ 116.5	$ 103.8	$ 2.9	$ 4.1	$ 227.3
2020	116.5	97.5	2.5	4.1	220.6
2021	116.0	92.1	2.1	4.0	214.2
2022	115.8	86.4	2.1	4.0	208.3
2023	118.1	80.5	2.2	3.9	204.7
2024 – 2028	499.7	318.6	23.0	18.5	859.8
2029 – 2033	333.6	224.6	35.8	15.3	609.3
2034 – 2038	372.2	148.0	43.6	11.2	575.0
2039 – 2043	337.7	69.4	53.3	6.2	466.6
2044 – 2048	168.0	15.2	30.0	0.9	214.1
Total	$ 2,294.1	$ 1,236.1	$ 197.5	$ 72.2	$ 3,799.9

Reserve Fund—The Department has created and is required under Ordinance No. 125459 (Bond Ordinance) to maintain a Reserve Fund for the purpose of securing the payment of the principal of and interest on all Parity Bonds outstanding and all amounts due under Parity Payment Agreements. The Reserve Fund is a pooled reserve and is an account within the books of the Department.

Reserve Fund Requirement—Under the Bond Ordinance, the aggregate Reserve Fund Requirement for all Parity Bonds is equal to the sum of the Reserve Fund Requirements established for each issue of Parity Bonds outstanding. The Bond Ordinance permits the City to establish the Reserve Fund Requirement (if any) for each issue of the Bonds or of Future Parity Bonds in connection with approving the sale of each such issue. Solely for purposes of setting the Reserve Fund Requirement, all series issued together under a single bond sale resolution are treated as a single "issue". Upon issuance of the 2018B and 2018C Bonds, the aggregate Reserve Fund Requirement for all Parity Bonds outstanding was $152.5 million. The Reserve Fund Requirement is satisfied by deposits of $79.9 million in cash held in the Reserve Fund and $72.6 million from the surety bond (see below). The reserve fund balance of $128.1 million at December 31, 2018 consisted of the $79.9 million in cash as noted above, $35.9 million in surety bond replacement funds, and a $12.3 million deposit from the 2018A bond proceeds. The reserve fund balance at December 31, 2017 of $103.6 million consisted of $67.6 million in cash, $30.7 million in surety bond replacement funds, and a $5.3 million deposit from the 2017C bond proceeds.

Surety Bond—Under the Bond Legislation, the City is permitted to provide for the Reserve Fund Requirement with an Alternate Reserve Security consistent with the Bond Legislation requirements. Under the Bond Legislation, a surety bond qualifies as Qualified Insurance for purposes of satisfying the Reserve Fund Requirement if the provider's ratings are in one of the top two rating categories at the time the policy is issued. The Bond Legislation does not require that the Reserve Fund be funded with cash or an Alternate Reserve Security if the provider of qualified insurance is subsequently downgraded. The City currently has a surety bond (the "Surety Bond") purchased from Assured Guaranty Municipal Corporation (AGM), with a policy limit that is equal to $72.6 million. This amount is used to satisfy a large proportion of the aggregate Reserve Fund Requirement.

AGM is currently rated A2 and AA by Moody's Investors Service and Standard & Poor's Ratings Services, respectively.

Irrevocable Trust Accounts—$198.2 million of the proceeds of the 2018B and 2018C refunding revenue Bonds were placed in a separate irrevocable trust account to refund the 2015B and 2017A&B Bonds on a current basis. There were balances outstanding in the irrevocable trust account during 2018 for prior lien bonds advance refunded or defeased with the 2017 bonds and balances outstanding for prior lien bonds advance refunded prior to 2018. The outstanding principal balance of all bonds defeased through 2018 and 2017 was $299.9 million as of December 31, 2018 and December 31, 2017, respectively. During 2018, none of the defeased bonds were called and paid from the 2017 irrevocable trust account. The irrevocable trust account established in 2018 paid in full the refunded 2015B and 2017A&B Bonds. Neither the assets of the trust accounts nor the liabilities for the defeased bonds are reflected in the Department's financial statements. Funds held in the 2017 irrevocable trust account at December 31, 2018 are sufficient to service and redeem the defeased bonds outstanding.

Bond Ratings—The 2018 and 2017 Bonds, along with other outstanding parity bonds, were rated "Aa2" and "AA"; and "Aa2" and "AA", by Moody's Investors Service, Inc. and Standard Poor's Rating Services, respectively.

Revenue Pledged—Revenue bonds are special limited obligations payable from and secured solely by the gross revenues of the Department, less charges for maintenance and operations, and by money in the debt service account and Reserve Fund. Principal and interest paid during 2018 and 2017 was $219.0 million and $209.3 million, respectively. Total revenue available for debt service as defined for the same periods was $388.4 million and $376.8 million, respectively. Annual interest and principal payments are expected to require 58.4% of revenues available for debt service for 2019 and required 58.0% in 2018.

Federal Arbitrage Regulations—Revenue bonds are subject to federal arbitrage regulations and the Department has complied with these regulations. The balance of federal arbitrage rebate liability was $0.4 million as of December 31, 2018 and 2017.

Other—There were no liens on property or revenue pertaining to parity bonds and all bond covenants were in compliance for the Department's prior lien bonds as of December 31, 2018 and 2017, respectively.

Fair Value— Debt is recorded and presented in the financial statements at carrying value net of premiums and discounts and shown below with fair values as provided by the Department's financial advisor, Piper Jaffray & Company. The fair value for the Department's bonds are estimated based on the quoted market prices for the same or similar issues or on the current rates offered to the Department for debt of the same remaining maturities. Carrying amounts and fair values at December 31, 2018 and 2017, were as follows:

($ in millions)	2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt:				
Prior lien bonds	$ 2,684.3	$ 2,645.2	$ 2,536.2	$ 2,551.3

Amortization—Discounts and premiums are amortized using the effective interest method over the term of the bonds.

The excess of costs incurred over the carrying value of bonds refunded on early extinguishment of debt is amortized as a component of interest expense using the effective interest method over the terms of the issues to which they pertain. Charges on advance refunding amortized to interest expense totaled $5.3 million in 2018 and $4.9 million in 2017. Charges on advance refunding in the amount of $31.0 million and $36.3 million are included as a component of Deferred Outflows of Resources on the 2018 and 2017 balance sheets, respectively.

10. NONCURRENT LIABILITIES—The Department had the following activities during 2018 and 2017:

($ in millions)	Balance at 1/1/18	Additions	Reductions	Balance at 12/31/18
2018				
Net pension liability	$ 288.8	$ -	$ (56.3)	$ 232.5
Accumulated provision for injuries and damages	96.1	16.4	(3.6)	108.9
Compensated absences	15.7	1.1	(1.8)	15.0
Other	9.0	0.4	-	9.4
Total	$ 409.6	$ 17.9	$ (61.7)	$ 365.8

	Balance at 1/1/17	Additions	Reductions	Balance at 12/31/17
2017				
Net pension liability	$ 317.8	$ -	$ (29.0)	$ 288.8
Accumulated provision for injuries and damages	92.0	4.7	(0.6)	96.1
Compensated absences	15.8	-	(0.1)	15.7
Other	8.0	1.0	-	9.0
Total	$ 433.6	$ 5.7	$ (29.7)	$ 409.6

Additional information on the Net pension liability can be found in Note 13 Seattle City Employees' Retirement System. Information about the provision for injuries and damages can be found in Note 11 Provision for Injuries and Damages and Note 15 Environmental Liabilities. Other includes primarily a liability for Other Postemployment Benefits; see Note 14 Other Postemployment Benefits.

11. PROVISION FOR INJURIES AND DAMAGES

The Department establishes liabilities for claims based on estimates of the ultimate projected cost of claims. Environmental related expenses are discussed in Note 15 Environmental Liabilities. The length of time for which such costs must be estimated varies depending on the nature of the claim. Actual claims costs depend on such factors as inflation, changes in doctrines of legal liability, damage awards, and specific incremental claim adjustment expenses. Claims liabilities are recomputed periodically using actuarial and statistical techniques to produce current estimates, which reflect recent settlements, claim frequency, industry averages, City-wide cost allocations, and economic and social factors. For 2018 and 2017, liabilities for lawsuits, claims, and workers' compensation were discounted over a period of 26 to 31 years at the City's average annual rate of return on investments, which was 1.70% and 1.45%, respectively.

To address the risk for certain losses arising from personal and property damage claims by third parties and for job-related illnesses and injuries to employees, the Department as part of the City of Seattle, has been self-insured for most of its general liability risks, for workers' compensation, and for employees' health care benefits. Effective June 1, 2018, the City had general liability insurance coverage for losses over a $6.5 million self-insured retention per occurrence with a $135 million limit per occurrence in the aggregate. Prior to June 1, 2018, the City had general liability insurance coverage for losses over a $6.5 million self-insured retention per occurrence with an $85 million limit per occurrence in the aggregate. The Department had no settled claims exceeding coverage in the last three years.

The City also purchased an all risk comprehensive property insurance policy that provides $500.0 million in limits subject to various deductible levels depending on the type of asset and value of the building. This includes $100.0 million in earthquake and flood limits. Hydroelectric and certain other utility producing and processing projects are not covered by the property policy. The City also purchased insurance for excess workers' compensation, fiduciary and crime liability, inland marine transportation, volunteers, and an assortment of commercial general liability, medical, accidental death and dismemberment, and miscellaneous policies. Bonds are purchased for public officials, public notaries, pension exposures, and specific projects and activities as necessary.

The changes in the provision for injuries and damages at December 31, 2018 and 2017 are as follows:

($ in millions)	2018	2017
Beginning unpaid claims liability	$ 14.3	$ 14.0
Payments	(2.2)	(4.7)
Incurred claims	(2.0)	5.0
Ending unpaid claims liability	$ 10.1	$ 14.3

The provision for injuries and damages included in current and noncurrent liabilities at December 31, 2018 and 2017 is as follows:

($ in millions)	2018	2017
Noncurrent liabilities	$ 6.8	$ 10.3
Accounts payable and other current liabilities	3.3	4.0
Total liability	$ 10.1	$ 14.3

12. ACCOUNTS PAYABLE

Accounts Payable and Other Current Liabilities—The composition of accounts payable and other current liabilities at December 31, 2018 and 2017, is as follows:

($ in millions)	2018	2017
Vouchers payable	$ 35.6	$ 34.8
Power accounts payable	25.6	23.1
Taxes payable	8.3	10.0
Claims payable	8.9	10.9
Guarantee deposit and contract retainer	28.1	20.8
Other accounts payable	5.9	2.5
Total	$ 112.4	$ 102.1

13. SEATTLE CITY EMPLOYEES' RETIREMENT SYSTEM

Plan Description—The Seattle City Employees' Retirement System (SCERS) is a cost-sharing multiple-employer defined benefit public employee retirement system, covering employees of the City and administered in accordance with Chapter 41.28 of the Revised Code of Washington and Chapter 4.36 of the Seattle Municipal Code. SCERS is a pension trust fund of the City. SCERS is administered by the Retirement System Board of Administration (the Board). The Board consists of seven members including the Chair of the Finance Committee of the Seattle City Council, the City of Seattle Finance Director, the City of Seattle Personnel Director, two active members and one retired member of the System who are elected by other system members, and one outside board member who is appointed by the other six board members. Elected and appointed board members serve for three-year terms.

All employees of the City are eligible for membership in SCERS with the exception of uniformed police and fire personnel who are covered under a retirement system administered by the State of Washington. Employees of the King County Departments of Transportation and Public Health who established membership in SCERS when these organizations were City departments were allowed to continue their SCERS membership.

Beginning with employees with hire dates of January 1, 2017 or later, all new members are enrolled in SCERS Plan II, which has contribution and benefit calculation rates different than the original SCERS I Plan.

Following is membership data for employees covered by the benefit terms as of the reporting date, December 31, 2018, and the measurement date, December 31, 2017 and the reporting date December 31, 2017, and the measurement date December 31, 2016:

	2018	2017
Active members	9,390	9,283
Retired members and beneficiaries receiving benefits	6,792	6,534
Vested terminated employees entitled to benefits	1,332	1,312

Summary of Significant Accounting Policies—SCERS financial statements and schedules are presented using the economic resources measurement focus and the accrual basis of accounting. For purposes of measuring the net pension liability (NPL), deferred outflows of resources and deferred inflows of resources related to pensions, and pension expense, information about the fiduciary net position of SCERS and additions to and deductions from SCERS fiduciary net position have been determined on the same basis as they are reported by SCERS. For this purpose, benefit payments (including refunds of employee contributions) are recognized when due and payable in accordance with the benefit terms. Investments are reported at fair value in accordance with GASB 72.

The NPL was measured as of December 31, 2017 and December 31, 2016, and the total pension liability used to calculate the NPL was based on an actuarial valuation as of January 1, 2017 and January 1, 2016, respectively.

Pension Benefits—Service retirement benefits are calculated on the basis of age, salary, and service credit.

SCERS I – Members are eligible for retirement benefits after 30 years of service, at age 52 after 20 years of service, at age 57 after 10 years of service, and at age 62 after 5 years of service. Annual retirement benefits are calculated as 2% multiplied by years of creditable service, multiplied by average salary, based on the highest 24 consecutive months, excluding overtime. Members who retire before meeting the age and/or years of service requirement receive a 0.1% reduction for each year that retirement precedes the date of eligibility. Retirement benefits vest after 5 years of credited service.

SCERS II – Members are eligible for retirement benefits at age 55 after 20 years of service, at age 57 after 10 years of service, and at age 60 after 5 years of service. Annual retirement benefits are calculated as 1.75% multiplied by years of creditable service, multiplied by average salary, based on the highest 60 consecutive months, excluding overtime. Members who retire before meeting the age and/or years of service requirement receive a 0.1% reduction for each year that retirement precedes the date of eligibility. Retirement benefits vest after 5 years of credited service.

Disability Benefits—An active member is eligible to receive disability benefits when: (a) member has achieved 10 years of credited service within the 15 years preceding disability retirement, or (b) the disability occurs in the course of City employment in which no service requirement exists. The amount of the disability benefit is the greater of (a) 1.5% times the final compensation times completed years of creditable service, or (b) 1.5% times final compensation total years of service that could have been earned to age 62, but not to exceed one-third of final compensation. Disability benefits vest after 10 years of credited service.

Death Benefits—Death benefits may be paid to a member's designated beneficiary. If a member's death occurs before retirement, the benefit options available are (a) payment to the beneficiary of accumulated contributions, including interest, or (b) if the member had completed 10 years of service at the time of death, a surviving spouse or registered domestic partner may elect to receive, in place of (a) above, either: (1) A monthly allowance for life equal to the benefit the spouse would have received had the member just retired with a 100% contingent annuitant option in force, or (2) A cash payment of no more than one-half of the member's accumulated contributions, along with a correspondingly reduced retirement allowance. If a member's death occurs after retirement, the death benefit received by the beneficiary (if any) is based on the retirement plan the member selected at retirement. Death benefits vest after 10 years of credited service.

Contributions—Member and employer contributions rates are established by Seattle Municipal Code Chapter 4.436. The overall contribution rate is determined by the actuarial formula identified as the Entry Age Cost Method. Member contribution rates are also set via collective bargaining contracts. The overall formula determines the amount of contributions necessary to fund the current service cost, representing the estimated amount necessary to pay for benefits earned by the employees during the current service year and the amount of contributions necessary to pay for prior service costs. Total required contributions, including amounts necessary to pay administrative costs, are determined through annual actuarial valuations. Contribution rates and amounts were as follows as of the reporting dates, December 31, 2018 and December 31, 2017, and the measurement dates, December 31, 2017 and December 31, 2016:

($ in millions)	Contributions					
	Rates				Amounts	
	SCERS I Employer	SCERS I Employee	SCERS II Employer	SCERS II Employee	City	Department
2018	15.23%	10.03%	14.42%	7.00%	$117.7	$24.7
2017	15.29%	10.03%	14.42%	7.00%	$112.1	$23.7

Net Pension Liability—The Department reported a liability of $232.5 million and $288.8 million for its proportionate share of net pension liability as of December 31, 2018 and December 31, 2017, respectively. The Department's proportion of the NPL as of December 31, 2018 and December 31, 2017 was based on contributions to SCERS during the fiscal year ended December 31, 2017 and December 31, 2016, respectively. The Department's proportionate share was 21.00% and 22.13% for the years ended December 31, 2017 and December 31, 2016, respectively. The net pension liability was measured as of December 31, 2017 and December 31, 2016, and the total pension liability used to calculate the net pension liability was based on an actuarial valuation as of January 1, 2017 and January 1, 2016, respectively.

Changes in Net Pension Liability

($ In millions)

	Fiscal Year Ended December 31	
	2018	**2017**
Total Pension Liability		
Service cost	$ 23.6	$ 23.6
Interest on total pension liability	59.1	59.3
Effect of economic/demographic gains or losses	(6.1)	(1.7)
Benefit payments	(37.6)	(37.4)
Refund of contributions	(4.0)	(3.7)
Net change in total pension liability	35.0	40.1
Total pension liability, beginning of period	839.5	883.5
Effect of change in proportionate share	(42.9)	(84.1)
Adjusted total pension liability, beginning of period	796.6	799.4
Total pension liability, end of period	831.6	839.5
Plan fiduciary net position		
Benefit payments	(37.6)	(37.4)
Refunds of contributions	(4.0)	(3.7)
Administrative expenses	(2.5)	(2.0)
Member contributions	15.4	15.9
Employer contributions	23.5	24.0
Net investment income	81.7	42.0
Net change in Plan fiduciary net position	76.5	38.8
Plan fiduciary net position, beginning of period	550.7	565.7
Effect of change in proportionate share	(28.1)	(53.8)
Adjusted fiduciary net position, beginning of period	522.6	511.9
Plan fiduciary net position, end of period	599.1	550.7
Net pension liability, end of period	$ 232.5	$ 288.8

The Department incurred pension expense of $21.8 million and $37.1 million for the years ended December 31, 2018, and 2017, respectively.

Actuarial assumptions—The total pension liability at December 31, 2018 and 2017, was based on actuarial valuations as of December 31, 2017 and 2016, respectively, using the following actuarial methods and assumptions:

Actuarial Cost Method	Individual Entry Age Normal
Amortization Method	
Level percent or level dollar	Level percent
Closed, open, or layered periods	Closed
Amortization Period and Start Date	30 years as of January 1, 2013 Valuation
Amortization Growth Rate	4.00%
Asset Valuation Method	
Smoothing period	5 years
Recognition method	Non-asymptotic
Corridor	None
Inflation	3.25%
Investment Rate of Return	7.50%
Post-retirement benefit increases	1.50%
Cost-of-living year-end bonus dividend	0.00%
Mortality	Various rates based on RP-2000 mortality tables and using generational projection of improvement using Projection Scale AA.

All other actuarial assumptions used in the December 31, 2017 valuation were based on the results of an actuarial experience study for the period January 1, 2010 through December 31, 2013, including updates to salary increase, mortality and retirement rates.

Discount Rate—The discount rate used to measure the total pension liability was 7.50%. The projection of cash flows used to determine the discount rate assumed that plan member contributions will be made at the current contribution rate and the participating governmental entity contributions will be made at rates equal to the difference between actuarially determined contribution rates and the member rate. Based on those assumptions, the pension plan's fiduciary net position was projected to be available to make all projected future benefit payments of current plan members. Therefore, the long-term expected rate of return on pension plan investments was applied to all periods on projected benefit payment to determine the total pension liability.

The long-term expected rate of return on pension plan investments was determined using a building-block method in which best-estimate ranges of expected future real rates of return (expected returns, net of pension plan investment expense and gross of administrative expenses) are developed for each major asset class. These ranges are combined to produce the long-term expected rate of return by weighting the expected future real rates of return by the target asset allocation percentage and by adding expected inflation.

The following table reflects long-term expected (30 year) real rate of return by asset class. The rate of return was calculated using the capital market assumptions applied to determine the discount rate and asset allocation. The expected inflation rate is projected at 3.25% for the same period.

Asset Category	Target Allocation	Long-Term Expected Real Rate of Return
Equity		
Public Equity	48.0%	4.94%
Private Equity	9.0%	6.25%
Fixed Income		
Core Fixed Income	16.0%	0.42%
Credit Fixed Income	7.0%	3.30%
Real Assets		
Real Estate	12.0%	3.66%
Infrastructure	3.0%	3.00%
Diversifying Strategies	5.0%	3.09%

Sensitivity of the Net Pension Liability to Changes in the Discount Rate—The following presents the Department's proportionate share of the net pension liability of SCERS, calculated using a discount rate of 7.50%, as well as what the Department's proportionate share of the net pension liability would be if it were calculated using a discount rate that is 1 percentage point lower (6.50%) or 1 percentage point higher (8.50%):

Discount Rate Sensitivity

(In millions)

	Net Pension Liability at December 31,	
	2018	2017
Discount Rate		
1% decrease - 6.50%	$ 333.2	$ 390.9
Current discount Rate - 7.50%	232.5	288.8
1% increase - 8.50%	147.8	203.0

Plan Fiduciary Net Position—Detailed information about the SCERS's fiduciary net position is available in the separately issued, audited financial statements as of December 31, 2018, which are publicly available at http://www.seattle.gov/retirement/about-us/board-of-administration.

Deferred Outflows of Resources and Deferred Inflows of Resources Related to Pension—The following table presents information about the pension-related deferred outflows of resources and deferred inflows of resources for the Department at December 31, 2018, and December 31, 2017:

($ in millions)	December 31,	
	2018	2017
Deferred outflows of resources		
Differences between expected and actual experience	$ 0.2	$ 0.3
Net difference between projected and actual earnings	-	22.9
Contributions made subsequent to measurement date	24.7	23.7
Total deferred outflows of resources	$ 24.9	$ 46.9
Deferred inflows of resources		
Differences between expected and actual experience	$ 6.0	$ 1.4
Net difference between projected and actual earnings	20.5	-
Differences between employer contributions and proportionate share of contributions	28.6	22.4
Total deferred inflows of resources	$ 55.1	$ 23.8

Department contributions made in 2018 in the amount of $24.7 million are reported as deferred outflows of resources and will be recognized as a reduction of the net pension liability in the year ended December 31, 2019. These contributions along with the net difference between projected and actual earnings reported as deferred outflows of resources will be recognized as pension expense in the future as shown in the following table. Department contributions made in 2017 in the amount of $23.7 million were previously reported as deferred outflows of resources and are recognized as a reduction of the net pension liability in the year ended December 31, 2018. Note that additional future deferred outflows and inflows of resources may impact these amounts.

Year Ending December 31 *($ in millions)*	Amortization
2019	$ (9.3)
2020	(11.1)
2021	(18.0)
2022	(14.7)
2023	(1.8)
Total	$ (54.9)

14. OTHER POSTEMPLOYMENT BENEFITS

Plan Description **–** Health care plans for active and retired employees are administered by the City of Seattle as single-employer defined benefit public employee health care plans.

Employees retiring under the City may continue their health insurance coverage under the City's health insurance plans for active employees. When a retired participant dies, the spouse remains fully covered until age 65 and covered by the Medicare supplement plan thereafter. Employees that retire with disability retirement under the City may continue their health coverage through the City with same coverage provisions as other retirees. Eligible retirees self-pay 100 percent of the premium based on blended rates which were established by including the experience of retirees with the experience of active employees for underwriting purposes. The postemployment benefit provisions are established and may be amended by ordinance of the Seattle City Council and as provided in Seattle Municipal Code 4.50.020. The City provides an implicit rate subsidy of the post-retirement health insurance costs and funds the subsidy on a pay-as-you-go basis. The City of Seattle covers 11,823 active employee plan participants and 398 retiree, disabled, and survivor plan participants as of the January 1, 2018 measurement date.

In 2018 the Department implemented GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* which concerns the accounting for and disclosure of other postemployment benefits. See Note 21, Implementation of New Accounting Standards, for more information regarding the implementation and financial impact on the Department's financial statements.

Actuarial valuations involve estimates of the value of reported amounts and assumptions about the probability of events far into the future. Actuarially determined amounts are subject to continual revision as actual results are compared to past expectations and new estimates are made about the future. Calculations are based on the types of benefits provided under the terms of the substantive plan at the time of each valuation and on the pattern of sharing of costs between the employer and plan members to that point. The projection of benefits for financial reporting purposes does not explicitly incorporate the potential effects of legal or contractual funding limitations on the pattern of cost sharing between the employer and plan members in the future. Actuarial calculations reflect a long-term perspective. Consistent with that perspective, actuarial methods and assumptions used include techniques that are designed to reduce short-term volatility in actuarial accrued liabilities and the actuarial value of assets. Based on the latest biennial actuarial valuation date the significant methods and assumptions are as follows:

Actuarial data and assumptions **–** the demographic assumptions of mortality, termination, retirement, and disability are set equal to the assumptions used for City pension actuarial valuations based on a Seattle City Employees' Retirement System Experience Report for the period 2014-2017.

Valuation date	January 1, 2018
Actuarial cost method	Entry age normal
Amortization method	Level dollar
Discount rate	3.44%
Health care cost trend rates—medical:	7.00% in 2018, decreasing to 6.77% in 2019, and decreasing by varying amounts until 2030 thereafter.
Health care cost trend rates—Rx:	10.00% in 2018, decreasing to 9.50% in 2019, and decreasing by varying amounts until 2030 thereafter.

Participation 25% of Active Employees who retire participate

Mortality

General Service (Actives)

Males: RP-2014 Employees Table for Males, adjusted by 60%.
Females: RP-2014 Employees Table for Females, adjusted by 95%
Rates are projected generationally using Scale MP-2014 ultimate rates

General Service (Retirees)

Males: RP-2014 Healthy Annuitant Males, adjusted by 95%
Females: RP-2014 Healthy Annuitant Females, adjusted by 95%
Rates are projected generationally using Scale MP-2014 ultimate rates

Marital status – 35% of members electing coverage: married or have a registered domestic partner. Male spouses two years older than their female spouses.

Health Care Claims Development – The sample per capita claim cost assumptions shown below by age, benefit, and plan represent the true underlying baseline experience estimated for the City of Seattle's sponsored postretirement benefits and costs.

	Aetna Preventive Plan			Aetna Traditional Plan		
Age	Medical	Rx	Admin	Medical	Rx	Admin
50	$9,368	$2,621	$465	$9,599	$2,731	$465
52	$10,191	$2,852	$465	$10,443	$2,970	$465
55	$11,563	$3,236	$465	$11,849	$3,370	$465
57	$12,603	$3,527	$465	$12,914	$3,673	$465
60	$14,341	$4,013	$465	$14,694	$4,180	$465
62	$15,452	$4,324	$465	$15,832	$4,504	$465

	Group Health Deductible			Group Health Standard		
Age	Medical	Rx	Admin	Medical	Rx	Admin
50	$4,534	$1,215	$734	$4,285	$1,097	$734
52	$4,932	$1,321	$734	$4,661	$1,193	$734
55	$5,596	$1,499	$734	$5,288	$1,353	$734
57	$6,099	$1,634	$734	$5,764	$1,475	$734
60	$6,939	$1,859	$734	$6,559	$1,679	$734
62	$7,476	$2,004	$734	$7,067	$1,810	$734

The average medical/Rx per capita claims costs were developed from calendar year 2019 fully insured premium rates for Aetna plans or self-funded premium-equivalent rates for Group Health (acquired by Kaiser Permanente in 2017) plans. Premium or premium-equivalent rates were provided by the City of Seattle's health pricing actuary. The average medical/Rx per capita claims costs were trended to the mid-point of the annual period following the valuation date. Average medical/ Rx per capita claims costs were then age-adjusted based on the demographics of the population, and the assumed health care aging factors shown in the morbidity factors table below.

For the Aetna plans only, the average medical/Rx per capita claims costs were blended with the 2017 medical/Rx per capital developed claims cost trended forward to the valuation date.

Morbidity Factors – The claim costs for medical and prescription drugs were assumed to increase with age according to the table below.

Age	Medical	Rx	Composite
40-44	3.0%	4.8%	3.3%
45-49	3.7%	4.7%	3.8%
50-54	4.2%	4.7%	4.3%
55-59	4.4%	4.6%	4.4%
60-64	3.7%	4.6%	3.8%
65-69	2.7%	3.8%	3.1%
70-74	1.8%	2.5%	2.1%
75-79	2.2%	0.8%	1.4%
80-84	2.8%	0.2%	1.3%
85-89	1.4%	0.1%	0.6%
90+	0.0%	0.0%	0.0%

Other Considerations – Active employees with current spouse and/or dependent coverage elect same plan and coverage. After retirement, it is assumed that children will have aged off of coverage and will have $0 liability.

Net OPEB Liability – The department reported an OPEB liability of $8.9 million in 2018. The Department's proportionate share of the OPEB liability was 14.61% for the year ended December 31, 2018. Based on the actuarial valuation date of January 1, 2018, details regarding the Department's Total OPEB Liability, Plan Fiduciary Net Position, and Net OPEB Liability as of December 31, 2018 are shown below.

Changes in Net OPEB Liability

($ in millions)	Total OPEB Liability	Plan Fiduciary Net Position	Net OPEB Liability
Changes recognized for the fiscal year:			
Service cost	$ 0.5	N/A	$ 0.5
Interest on the total OPEB liability	0.4	N/A	0.4
Differences between expected and actual experience	2.0	N/A	2.0
Changes of assumptions	(3.3)	N/A	(3.3)
Benefit payments	(0.3)	(0.3)	-
Contributions from the Employer	-	0.3	(0.3)
Net Changes	(0.7)	-	(0.7)
Balance recognized at 12/31/2017	9.6	-	9.6
Balance recognized at 12/31/2018	$ 8.9	$ -	$ 8.9

The Department recorded an expense for OPEB of $0.8 million in 2018. The Health Care Subfund of the General Fund is reported in The City of Seattle's Comprehensive Annual Financial Report.

Discount Rate and Healthcare Cost Trend Rates – The discount rate used to measure the total OPEB liability for is 3.44% for 2018. The following tables present the sensitivity of net OPEB liability calculation to a 1% increase and a 1% decrease in the discount rate used to measure the total OPEB liability:

Discount Rate Sensitivity

(In millions)

	Net OPEB Liability at December 31, 2018	
Discount Rate		
1% decrease - 2.44%	$	9.8
Current discount Rate - 3.44%		8.9
1% increase - 4.44%		8.1

The following table presents the sensitivity of net Health Plan OPEB liability calculation to a 1% increase and a 1% decrease in the healthcare cost trend rates used to measure the total Health Plan OPEB liability:

Healthcare Cost Trend Rate Sensitivity

(In millions)

	Net OPEB Liability at December 31, 2018	
Discount Rate		
1% decrease	$	7.9
Trend rate		8.9
1% increase		10.1

Deferred Outflows of Resources and Deferred Inflows of Resources Related to OPEB – The following table presents information about the OPEB-related deferred outflows of resources and deferred inflows of resources for the Department at December 31, 2018.

($ in millions)		Deferred Outflows		Deferred Inflows
Difference between actual and expected experience	$	1.8	$	-
Assumption changes		-		2.9
Contributions made in 2018 after measurement date		0.3		N/A
Total	$	2.1	$	2.9

Department contributions made in 2018 in the amount of $0.3 million are reported as deferred outflows of resources and will be recognized as a reduction of the net OPEB liability in the year ended December 31, 2019. These contributions will be recognized in the future as shown in the following table. Note that additional future deferred outflows and inflows of resources may impact these amounts.

Year Ending December 31 *($ in millions)*	Amortization
2019	$ (0.1)
2020	(0.2)
2021	(0.1)
2022	(0.2)
2023	(0.1)
Total Thereafter	(0.4)
Total	$ (1.1)

Following are the disclosures for December 31, 2017 under GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other than Pensions*.

Based on the actuarial valuation date of January 1, 2017, the City's annual cost for fiscal years ended December 31, 2017, the amount of expected contribution to the plan, and changes in net obligation are as follows:

($ in millions)	2017
Annual required contribution	$ 8.1
Interest on net OPEB obligation	1.7
Adjustment to annual required contribution	(2.8)
Annual OPEB cost (expense)	7.0
Expected contribution (employer-paid benefits)	(2.3)
Increase in net OPEB obligation	4.7
Net OPEB obligation - beginning of the year	54.1
Net OPEB obligation - end of year	$ 58.8

The department reported an OPEB liability of $8.6 million in 2017. The Department's proportionate share of the OPEB liability was 14.64% for the year ended December 31, 2017. The Department's portion of the expected contribution was $0.3 million. The Department recorded an OPEB expense of $0.7M in 2017.

The schedules of funding progress ($ in millions) (unaudited) are as follows:

Actuarial Valuation Date January 1	Actuarial Value of Assets (A)	Actuarial Accrued Liabilities (AAL) Entry Age (B)	Unfunded AAL (UAAL) (B-A)	Funding Ratio (A/B)	Covered Payroll (C)	UAAL as a Percentage of Covered Payroll ((B-A)/C)
2014	-	$ 41.8	$ 41.8	-	$ 1,004.0	4.2 %
2016	-	65.7	65.7	-	1,125.7	5.8

Actuarial data and assumptions

Valuation date	January 1, 2016
Actuarial cost method	Entry age normal
Amortization method	Level dollar
Initial amortization period	30 years, open
Discount rate	3.09%
Health care cost trend rates—medical -	6.25% in 2017, decreasing to 6% in 2018, and decreasing by varying amounts until 2025 thereafter.

40% of Active Employees who retire participate

Mortality – General Service Actives and Retirees based on RP-2000 Table and RP-2000 Combined Healthy, respectively, with ages set back six years for male and female actives; set back two years for male retirees and one year for female retirees. Rates are generational for both males and females using Projection Scale AA.

Marital status – 45% of members electing coverage: married or have a registered domestic partner. Male spouses two years older than their female spouses.

Health Care Claims Development The average medical/Rx per capita claims costs were developed from calendar year fully insured premium rates for Aetna plans or self-funded premium-equivalent rates for Group Health (acquired by Kaiser Permanente in 2017) plans. Premium or premium-equivalent rates were provided by the City of Seattle's health pricing actuary. The average medical/Rx per capita claims costs were trended to the mid-point of the annual period following the valuation date. Average medical/ Rx per capita claims costs were then age-adjusted based on the demographics of the population, and the assumed health care aging factors shown in the morbidity factors table below.

For the Aetna plans only, the average medical/Rx per capita claims costs were blended with the average medical/Rx per capita claims costs developed from actual active claims experience and enrollment for the two-year period January 1, 2015 through December 31, 2016. Claims and enrollment information was provided by Aetna. Claims experience was adjusted for differences in plan design between the historical periods and the projection period using plan design relative values from Aon Hewitt's actuarial models. No adjustment was made for large claims. The average medical/Rx per capita claims costs from each respective historical base period were trended to the mid-point of the annual period following the measurement date. In order to improve the credibility of a single projection estimate, a combination of estimates from the distinct historical periods was used, placing 50% credibility on the most recent period and 50% on the next most recent.

Morbidity Factors – The claim costs for medical and prescription drugs were assumed to increase with age according to the table below.

Age	Medical	RX	Composite
40-44	3.0%	4.8%	3.3%
45-49	3.7%	4.7%	3.8%
50-54	4.2%	4.7%	4.3%
55-59	4.4%	4.6%	4.4%
60-64	3.7%	4.6%	3.8%
65-69	2.7%	3.8%	3.1%
70-74	1.8%	2.5%	2.1%
75-79	2.2%	0.8%	1.4%
80-84	2.8%	0.2%	1.3%
85-89	1.4%	0.1%	0.6%
90+	0.0%	0.0%	0.0%

Other considerations – Active employees with current spouse and/or dependent coverage elect same plan and coverage. After retirement, it is assumed that children will have aged off of coverage and will have $0 liability

15. ENVIRONMENTAL LIABILITIES

Environmental liabilities were $107.7 million and $92.7 million, at December 31, 2018, and 2017, respectively.

The following is a brief description of the significant Superfund sites:

- *The Harbor Island Superfund Site*—In 1983, the U.S. Environmental Protection Agency (EPA) designated this site as a federal Superfund site. The Department and other entities are sharing costs equally for investigating contamination in the East Waterway alongside Harbor Island. The City share is split between the Department 45% and Seattle Public Utilities (SPU) 55%. The Department's involvement stems from its sale of transformers to a company on Harbor Island. The City of Seattle is one of four parties who are conducting remedial investigation and feasibility study that will delineate cleanup actions. A draft final feasibility study was submitted to EPA in October 2016. Nine alternative actions were presented with costs ranging from $256.0 million to $411.0 million with an estimated time to complete construction on active cleanup components ranging from 9 to 13 years. The EPA, however, has not identified the cleanup construction timing and cost estimate at this time. The project manager has identified that the total liability may be up to $300.0 million, of which, $100.0 million is the City share. The Department recorded its share of the estimated liability of $45.0 million in October 2016 in accordance with GASB Statement No. 49. The Feasibility Study (FS) was completed in 2017. There was no change in the estimated liability. The final FS will be submitted to EPA in 2019 and the proposed plan is expected to be released sometime in 2019. Ongoing work is expected to cost the City $0.7 million. While the timing of clean-up construction will not be known until the Agency identifies a preferred remedy, the final FS has identified a range of costs on which the clean-up estimate is based. The Department's ultimate liability is indeterminate.

- *The Lower Duwamish Waterway Superfund Site*—In 2001, the EPA designated this site as a federal Superfund site for contaminated sediments. The Department's involvement is attributable to its land ownership or use of property along the river. The City of Seattle is one of four parties who signed an Administrative Order on Consent (AOC) with the EPA and Washington State Department of Ecology (DOE) to conduct a remedial investigation and feasibility study to prepare a site remedy. The EPA approved the feasibility study in November 2012. In February 2013, the EPA issued the Proposed Plan for cleanup of the Lower Duwamish Waterway. In December 2014, the EPA issued its final Record of Decision (ROD) indicating its preferred alternative clean-up with a discounted estimated cost of $342.0 million, from the total estimated cost of $394.0 million. This estimate was recalculated to its 2018 current value using a starting point of the undiscounted estimated cost of $394.0 million plus an average Marine Construction Inflation Factor of 1.038 annually. This recalculation resulted in an increase in estimated environmental liability of $12.3 million for the Department for a revised estimated total project cost of $504.2 million.

  There have been four amendments to the AOC. The first amendment required Lower Duwamish Waterway Group (LDWG) to complete the Fisher Study which was completed in 2016; the second amendment required the completion of carbon study which was constructed in the first quarter of 2017 and will continue through 2020; and the third amendment required additional pre-design activities. The workplan for pre-design work was approved by EPA in August 2017 and is expected to continue through 2020. The extent and cost of additional investigation work required prior to implementation of remedy is still unknown. In July 2018, EPA issued a 4^{th} amendment to the AOC requires LDWG to (1) Design the remedy for river mile 3.0 to river mile 5 of Lower Duwamish Waterway Site (the "LDW Upper Reach"), consistent with the Lower Duwamish Waterway ROD and CERCLA; (2) incorporate and supersede the work being carried out under the Third Amendment to this AOC in support of the development of seafood consumption institutional controls for the Site; and (3) provide for timely periodic monitoring of selected site conditions, as necessary. The Department's ultimate liability is indeterminate.

In November 2012, the EPA issued general notification letters to parties informing them of their potential liability for the Lower Duwamish Waterway cleanup. The City and other three parties who signed the AOC with the EPA agreed to invite some of those parties to participate in an alternative dispute resolution process (the "allocation process") to resolve their respective shares of past and future costs. There are 44 parties participating in allocation. The City hired an allocator and the allocation process began in April 2014. The Department agreed to administer the allocator's contract, estimated to cost about $4.0 million over a four-year period. Parties participating in the allocation process will share the cost of the allocator and the process.

The City is also responsible for investigation and cleanup at the Port of Seattle Terminal 117 Streets, Uplands and Sediments sites. The South Park street is not owned by the Department, but the City has jurisdiction over the streets and right-of-ways. Remediation activities for streets was completed in August 2016. The City's share for the uplands and sediments site is paid 100% by the Department. The City's share for the adjacent streets is split between the Department and SPU according to a Memorandum of Agreement (MOA) signed in August 2014. According to this MOA, SPU will pay 2.5% for some portions of the construction and up to 100% for other parts of the cleanup and restoration. The final construction closeout and project closeout was approved by EPA in July 2018. In September 2018, the Long-term Monitoring and Maintenance Plan (LTMMP) was approved by EPA. An annual report will be submitted each year with the first report submitted in March 2019.

- *South Park Marina*—The Washington Department of Ecology has notified the City that it is a Potentially Liable Party for contamination at South Park Marina, which is adjacent to Terminal 117. The Department is the lead for the City at this site. Negotiations for an Agreed order between Ecology and Potential Liable Parties (PLP) have resulted in an Agreed order to conduct a Remedial Investigation only. The final Order is with PLPs for signatures. The City is going to administer the contract with common consultants. The City, the Port of Seattle and South Park Marina have agreed to share costs equally. City share is split between the Department 97.5% and SPU 2.5%. The Department's ultimate liability is indeterminate.

- *North Boeing Field/Georgetown Steam Plant*—The City, King County, and Boeing signed an Administrative Order issued by the Washington State Department of Ecology (Ecology) requiring them to investigate and possibly remove contamination in an area that encompasses North Boeing Field, the Department's Georgetown Steam Plant, and the King County Airport. This site was also the subject of the lawsuit brought by the City against Boeing. Boeing agreed to pay 67% of the costs for Ecology's implementation of the current order. The order requires completion and then implementation of a remedial investigation and feasibility. The final Remedial Investigation (RI) work plan was issued in November 2013. In January 2015, all parties executed the First Amendment to the North Boeing Field/Georgetown Steam Plant Agreed Order, making the PRPs responsible for conducting and completing remedial action at the site. The City is responsible for 1/3 of the costs, with the Department's share at 90% and SPU's share at 10%. The draft RI was submitted in June 2016. DOE directed additional investigation in offsite area following the submittal of RI. The additional investigation and negotiation on RI comments has delayed the submittal of the revised draft RI until 2019. The FS process will begin following approval of RI. Costs to date are approximately $8.3 million with an additional $0.7 million projected through completion of the FS. Boeing and the City will each pay 100% of costs for remedial action at their own facilities. The final liability is indeterminate.

The Department has included in its estimated liability those portions of the environmental remediation work that are currently deemed to be reasonably estimable.

Cost estimates were developed using the expected cash flow technique in accordance with GASB Statement No. 49. Estimated outlays were based on current cost and no adjustments were made for discounting or inflation. Cost scenarios were developed that defined a particular solution for a given site. Scenarios considered relevant potential requirements and alternatives for remediation of a site. Costs were calculated on a weighted average that was based on the probabilities of each scenario being selected and reflected cost-sharing agreements in effect. In addition, certain estimates were derived from independent engineers and consultants. The estimates were made with the latest information available; as new information becomes available, estimates may vary significantly due to price increases or reductions, technology, or applicable laws or regulations.

The Department is aggressively pursuing other third parties that may have contributed to the contamination of superfund sites for appropriate cost sharing. The Department's estimate for realized recoveries was $0.2 million and $3.8 million at December 31, 2018, and 2017, respectively, primarily representing an interfund receivable from SPU for recovery of remediation costs incurred related to the lower Duwamish Waterway site. The Department's estimate for not yet realized recoveries from other parties for their share of remediation work performed that partially offset the Department's estimated environmental liabilities was zero at December 31, 2018, and 2017. As of December 31, 2018, and 2017, environmental costs of $113.7 million and $93.1 million were deferred primarily for cleanup estimates of the Department's responsibility for the Lower Duwamish Waterway and East Waterway Superfund Sites; and these costs are being amortized and will be recovered through future rates in accordance with GASB Statement No. 62.

The changes in the provision for environmental liabilities at December 31, 2018, and 2017 were as follows:

($ in millions)	2018	2017
Beginning environmental liability, net of recoveries	$ 92.7	$ 86.7
Payments	(2.0)	(5.0)
Incurred environmental liability	17.0	11.0
Ending environmental liability, net of recoveries	$ 107.7	$ 92.7

The provision for environmental liabilities included in current and noncurrent liabilities at December 31, 2018 and 2017, was as follows:

($ in millions)	2018	2017
Noncurrent liabilities	$ 102.1	$ 85.8
Accounts payable and other current liabilities	5.6	6.9
Ending liability	$ 107.7	$ 92.7

16. OTHER LIABILITIES

Other liabilities include unearned capital fees which are amortized to revenues as earned, deposits that are returned to customers, and certain other unearned revenues which expire at contract completion.

Other liabilities at December 31, 2018 and 2017 consisted of the following:

($ in millions)	2018	2017
Other liabilities:		
Unearned capital fees	$ 24.4	$ 27.8
Customer deposits—sundry sales	12.7	7.9
Unearned revenues—other	0.7	0.6
Total	$ 37.8	$ 36.3

17. DEFERRED INFLOWS OF RESOURCES

Seattle City Council passed resolutions authorizing the reporting of certain credits as regulatory liabilities in accordance with Statement No. 62 of the GASB, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements*.

The unearned revenue for the Rate Stabilization Account for 2018 and 2017 is the result of spreading retail electric revenues and related activity over multiple periods to reduce the need for rapid and substantial rate increases (see Note 4 Rate Stabilization Account). Payments received from Bonneville's Energy Conservation Agreement are amortized to revenues over 20 years.

In accordance with the requirements of GASB Statement No. 68, *Accounting and Financial Reporting for Pensions – an amendment of GASB Statement No. 27*, decreases in Net Pension Liability resulting from changes in employer proportion and differences between contributions and proportionate share of pension expense are recognized as deferred inflows of resources. These deferred inflows are amortized over a closed five-year period. See Note 13 Seattle City Employees' Retirement System for more information.

On January 1, 2018, the Department implemented GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions (OPEB),* which concerns the accounting for and disclosure of other postemployment benefits. As a result of this implementation, amounts related to assumption changes are recognized as deferred inflows of resources, which are amortized over a closed five-year period. See Note 14 Other Postemployment Benefits for more information.

For 2017, Bonneville Slice contract true-up credits are reported as regulatory liabilities in the year invoiced and recognized as revenue in the following year. Effective October 1, 2017 there was an amendment to the agreement whereby the Department no longer participates as a Slice customer and will now exclusively purchase Block. Seattle City Council affirmed the Department's practice of recognizing the effects of reporting the fair value of exchange contracts in future periods for rate making purposes and maintaining regulatory accounts to spread the accounting impact of these accounting adjustments, in Resolution No. 30942 adopted January 16, 2007 (see Note 19 Long-Term Purchased Power, Exchanges, and Transmission).

Deferred inflows of resources at December 31, 2018 and 2017 consisted of the following:

($ in millions)	2018	2017
Deferred inflows of resources:		
Unearned revenue—rate stabilization account	$ 71.9	$ 68.4
Changes in Net Pension Liability	55.1	23.8
Changes in OPEB Liability	2.9	-
Bonneville energy conservation agreement	34.0	29.3
Bonneville Slice true-up credit	-	1.4
Exchange energy: regulatory gain	-	0.7
Total	$ 163.9	$ 123.6

18. SHORT-TERM ENERGY CONTRACTS AND DERIVATIVE INSTRUMENTS

The Department engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve the Department's load obligations and using these resources to capture available economic value. The Department makes frequent projections of electric loads at various points in time based on, among other things, estimates of factors such as customer usage and weather, as well as historical data and contract terms. The Department also makes recurring projections of resource availability at these points in time based on variables such as estimates of stream flows, availability of generating units, historic and forward market information, contract terms, and experience. Based on these projections, the Department purchases and sells wholesale electric capacity and energy to match expected resources to expected electric load requirements, and to realize earnings from surplus energy resources. These transactions can be up to 24 months forward. Under these forward contracts, the Department commits to purchase or sell a specified amount of energy at a specified time, or during a specified time in the future. Except for limited intraday and interday trading to take advantage of owned hydro storage, the Department does not take market positions in anticipation of generating profit. Energy transactions in response to forecasted seasonal resource and demand variations require approval by the Department's Risk Oversight Council.

It is the Department's policy to apply the normal purchase and normal sales exception of Statement No. 53 of the GASB, *Accounting and Financial Reporting for Derivative Instruments*, as appropriate. Certain forward purchase and sale of electricity contracts meet the definition of a derivative instrument but are intended to result in the purchase or sale of electricity delivered and used in the normal course of operations. Accordingly, the Department considers these forward contracts as normal purchases and normal sales under GASB Statement No. 53. These transactions are not required to be recorded at fair value in the financial statements.

The undiscounted aggregate contract amounts, fair value, and unrealized gain or (loss) of the Department's commodity derivative instruments qualifying as normal purchases and normal sales at December 31, 2018 and 2017 consisted of the following:

($ in millions)

2018	Aggregate Contract Amount	Aggregate Fair Value	Unrealized Gain (Loss)
Sales	$ 22.3	$ 24.7	$ (2.4)
Purchases	-	-	-
Total	$ 22.3	$ 24.7	$ (2.4)

2017	Aggregate Contract Amount	Aggregate Fair Value	Unrealized Gain (Loss)
Sales	$ 20.0	$ 19.1	$ 0.9
Purchases	3.3	3.1	(0.2)
Total	$ 23.3	$ 22.2	$ 0.7

All derivative instruments not considered as normal purchases and normal sales are to be recorded within the financial statements using derivative accounting according to GASB Statement No. 53. In 2010, the Seattle City Council adopted a resolution granting the Department authority to enter into certain physical put and call options that would not be considered normal purchases and normal sales under GASB Statement No. 53. The Department did not have any such activity for 2018 and 2017. In addition, the Seattle City Council has deferred recognition of the effects of reporting the fair value of derivative financial instruments for rate-making purposes, and the Department maintains regulatory accounts to defer the accounting impact of these accounting adjustments in accordance with GASB Statement No. 62, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB and AICPA Pronouncements* (see Note 7 Other Assets and Note 17 Deferred Inflows of Resources).

Market Risk—Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Market risk may also be influenced by the number of active, creditworthy market participants, and to the extent that nonperformance by market participants of their contractual obligations and commitments affects the supply of, or demand for, the commodity. Because the Department is active in the wholesale energy market, it is subject to market risk.

Credit Risk—Credit risk relates to the potential losses that the Department would incur as a result of nonperformance by counterparties of their contractual obligations to deliver energy or make financial settlements. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. The Department seeks to mitigate credit risk by: entering into bilateral contracts that specify credit terms and protections against default; applying credit limits and duration criteria to existing and prospective counterparties; and actively monitoring current credit exposures. The Department also seeks assurances of performance through collateral requirements in the form of letters of credit, parent company guarantees, or prepayment.

The Department has concentrations of suppliers and customers in the electric industry including: electric utilities; electric generators and transmission providers; financial institutions; and energy marketing and trading companies. In addition, the Department has concentrations of credit risk related to geographic location as it operates in the western United States. These concentrations of counterparties and concentrations of geographic location may impact the Department's overall exposure to credit risk, either positively or negatively, because the counterparties may be similarly affected by changes in conditions.

Other Operational and Event Risk—There are other operational and event risks that can affect the supply of the commodity, and the Department's operations. Due to the Department's primary reliance on hydroelectric generation, the weather, including spring time snow melt, runoff, and rainfall, can significantly affect the Department's operations. Other risks include regional planned and unplanned generation outages, transmission constraints or disruptions, environmental regulations that influence the availability of generation resources, and overall economic trends.

19. LONG-TERM PURCHASED POWER, EXCHANGES, AND TRANSMISSION

Bonneville Power Administration—The Department purchases electric energy from the U.S. Department of Energy, Bonneville Power Administration (Bonneville) under the Block and Slice Power Sales Agreement, a 17-year contract, for the period October 1, 2011 through September 30, 2028. Effective October 1, 2017 there was an amendment to the agreement whereby the Department no longer participates as a Slice customer and will now exclusively purchase Block. Block quantities are expected to be recalculated periodically during the term of the contract. Rates will be developed and finalized every two years. Accordingly, certain estimates and assumptions were used in the calculations in the estimated future payments table below.

The terms of the Slice product specified that the Department would receive a percentage of the actual output of the Federal Columbia River Power System (the System). The percentage was adjusted annually with a Slice Adjustment Ratio no greater than 1.0 times the 3.65663 initial slice percentage, no later than 15 days prior to the first day of each federal fiscal year, beginning with fiscal year 2012. The 2017 Slice percentage was 3.62643%, the same as the previous fiscal year. The cost of Slice power was based on the Department's same percentage of the expected costs of the System and was subject to true-up adjustments based on actual costs with specified exceptions.

Bonneville's Residential Exchange Program (REP) was established as a mechanism to distribute financial benefits of the Federal Columbia River Power System to residential customers of the region's investor owned utilities (IOUs). In May 2007, the Ninth Circuit Court (the Court) rulings found the 2000 REP Settlement Agreements with IOUs inconsistent with the Northwest Power Act. To remedy this inconsistency, the Court ruled that refunds be issued to non-IOUs through 2019. The Department received $5.7 million in both 2018 and 2017 in billing credits related to both the Block and Slice agreements as a result of the Court decision.

Lucky Peak—In 1984, the Department entered into a purchase power agreement with four irrigation districts to acquire 100% of the net surplus output of a hydroelectric facility that began commercial operation in 1988 at the existing Army Corps of Engineers Lucky Peak Dam on the Boise River near Boise, Idaho. The irrigation districts are owners and license holders of the project, and the FERC license expires in 2030. The agreement, which expires in 2038, obligates the Department to pay all ownership and operating costs, including debt service, over the term of the contract, whether or not the plant is operating or operable.

The Department incurred $7.8 million and $9.3 million in 2018 and 2017, respectively, including operations costs and royalty payments to the irrigation districts. The Department provided and billed Lucky Peak $0.3 million for operational and administrative services in both 2018 and 2017. These amounts are recorded as offsets to purchased power expense.

The Department's receivables from Lucky Peak were less than $0.1 million at December 31, for both 2018, and 2017. The Department's payables to Lucky Peak were $0.8 million at December 31, for both 2018, and 2017.

British Columbia—High Ross Agreement—In 1984, an agreement was reached between the Province of British Columbia and the City under which British Columbia will provide the Department with energy equivalent to that which would have resulted from an addition to the height of Ross Dam. Delivery of this energy began in 1986 and is to be received for 80 years. In addition to the direct costs of energy under the agreement, the Department incurred costs of approximately $8.0 million in prior years related to the proposed addition and was obligated to help fund the Skagit Environmental Endowment Commission through four annual $1.0 million payments. These other costs are included in utility plant-in-service as an intangible asset and are being amortized to purchase power expense over 35 years through 2035 (see Note 3 Utility Plant).

Expenses incurred, and energy received under these and other long-term purchased power agreements at December 31, 2018 and 2017 were as follows:

	Expense		Average Megawatts	
($ in millions)	2018	2017	2018	2017
Bonneville Block	$ 164.7	$ 103.8	506.4	347.7
Bonneville Slice	-	64.3	-	278.2
Long-term purchased power-Bonneville	164.7	168.1	506.4	625.9
Lucky Peak	7.8	9.3	39.7	52.9
British Columbia - High Ross Agreement	13.5	13.4	35.5	35.8
Grant County Public Utility District	1.5	1.9	2.9	2.8
Columbia Basin Hydropower	6.7	6.8	27.5	26.1
Bonneville South Fork Tolt billing credit	(3.3)	(3.3)	-	-
Renewable energy - State Line Wind	23.9	22.1	39.1	37.7
Renewable energy - Other	7.5	7.7	13.1	13.5
Exchanges and loss returns energy at fair value	2.9	3.7	50.4	50.1
Long-term purchased power booked out	(7.4)	(4.9)	(32.2)	(28.9)
Long-term purchase power-other	53.1	56.7	176.0	190.0
Total	$ 217.8	$ 224.8	682.4	815.9

Renewable Energy Purchase and/or Exchanges—The Energy Independence Act, Chapter 19.285 Revised Code of Washington, requires all qualifying utilities in Washington State to meet certain annual targets of eligible new renewable resources and/or equivalent renewable energy credits (RECs) as a percentage of total energy delivered to retail customers. The annual targets are: at least 9% by 2016, and at least 15% by 2020. The Department's 2018 and 2017 resource portfolio is adequate to meet the 9% target.

Energy Exchange—Northern California Power Agency (NCPA) and the Department executed a long-term Capacity and Energy Exchange Agreement in March 1993. The Department delivers energy to NCPA from June through October 15. NCPA returns energy under conditions specified in the contract at a 1.2:1 ratio of exchange power, from November through April. The agreement included financial settlement and termination options. In a letter NCPA dated May 17, 2011, NCPA gave seven year's advance written notice to the Department to terminate the agreement. Effective May 31, 2018, the agreement was officially terminated.

Fair Value of Exchange Energy—Exchange energy receivable and the related regulatory gains at December 31, 2018 and 2017, were valued using Kiodex Forward Curves, and Dow Jones U.S. Daily Electricity Price Indices for settled deliveries. An income valuation technique that uses interest rate forecasts from HIS Global Insight is used to discount for present value based on the interest rate for U.S. Government Treasury constant maturities, bond-equivalent yields by the future month of the transactions (see Note 2 Fair Value Measurement and Note 17 Deferred Inflows of Resources).

Estimated Future Payments Under Purchased Power, Transmission and Related Contracts—The Department's estimated payments for purchased power and transmission, RECs, and other contracts for the period from 2019 through 2065, undiscounted, are as follows:

Years Ending December 31 *($ in millions)*	**Estimated Payments**
2019[a]	$ 290.4
2020[b]	303.0
2021	289.9
2022	284.3
2023	284.9
2024-2028[c][d]	1,273.2
2029-2033	107.3
Thereafter (through 2065)	102.1
Total	$ 2,935.1

[a] 2019 includes estimated REP recoveries from Bonneville.
[b] British Columbia - High Ross direct cost payments end in 2020.
[c] Bonneville transmission contract expires July 31, 2025.
[d] Bonneville Block contract expires Sept 30, 2028.

20. COMMITMENTS AND CONTINGENCIES

Operating Leases—While the Department owns several buildings including those at the Skagit and Boundary hydroelectric projects, service centers, and the System Control Center, the Department leases some administrative office space from the City. Such lease payments to the City are made through a central cost allocation process, similar to all other payments for tenancy of City property. These payments are not included in the operating leases table below. The Department also leases certain office equipment and smaller facilities for various purposes through long-term operating lease agreements. Expenses for all operating leases totaled $0.5 million in 2018 and $1.9 million in 2017.

Minimum payments under the operating leases are:

Year Ending December 31 *($ in millions)*	Minimum Payments
2019	$ 1.6
2020	1.4
2021	1.5
Thereafter	-
Total	$ 4.5

2019 Capital Program—The budget for the Department's 2019 program for capital improvement, conservation, and deferred operations and maintenance including required expenditures on assets owned by others is $399.6 million. At December 31, 2018, the Department had approximately $142.8 million in commitments relating thereto. Department overhead costs and other allocations associated with the capital program are not included in the budget amount.

2019 Operations and Maintenance Budget—The Department's 2019 Operating and Maintenance budget is $974.9 million for labor and related benefits, purchased power, outside services, supplies, taxes, injuries and damages, interest, debt-related costs, maintenance of Department assets, and other non-capital expenditures incurred in the normal course of operations.

Federal Energy Regulatory Commission Fees—Estimated Federal land use and administrative fees related to hydroelectric licenses total $174.8 million through 2055; these estimates are subject to change. The estimated portion of fees attributed to the Skagit and Tolt licenses are excluded after 2025, when their existing FERC licenses expire. The estimated portion of Boundary fees is included through 2055, the year the current license issued by FERC expires. The Boundary FERC license and related issues are discussed below.

New Boundary License—The Department's FERC license for the Boundary Project expired on September 30, 2011 and a new license was issued on March 20, 2013 with a 42-year life and a total cost of $48.6 million. The terms and conditions of the new license have been evaluated and the Department is in the license implementation process, which imposes mitigation of endangered species including water quality standards and conservation management.

As part of the application process, the Department negotiated a settlement with external parties such as owners of other hydroelectric projects, Indian tribes, conservation groups and other government agencies. The settlement sought to preserve the Department's operational flexibility at Boundary Dam while providing for natural resource protection, mitigation and enhancement measures.

The cost projections for such mitigation over the expected 42-year life of the license, included in the Department's license application, were estimated to be $408.8 million adjusted to 2018 dollars, of which $74.5 million were expended through 2018. Projected mitigation cost estimates are subject to revision as more information becomes available.

Skagit and South Fork Tolt Licensing Mitigation and Compliance—In 1995, the FERC issued a license for operation of the Skagit hydroelectric facilities through April 30, 2025. On July 20, 1989, the FERC license for operation of the South Fork Tolt hydroelectric facilities through July 19, 2029, became effective. As a condition for both licenses, the Department has taken and will continue to take required mitigating and compliance measures.

Total Skagit license mitigation costs from the effective date until expiration of the federal operating license were estimated at December 31, 2018, to be $140.8 million, of which $129.2 million had been expended. Total South Fork Tolt license mitigation costs were estimated at $1.9 million, of which $1.4 million were expended through 2018. In addition to the costs listed for South Fork Tolt mitigation, the license and associated settlement agreements required certain other actions related to wildlife studies and wetland mitigation for which no set dollar amount was listed. Requirements for these actions have been met, and no further expenditures need to be incurred for these items.

Capital improvement, other deferred costs, and operations and maintenance costs are included in the estimates related to the settlement agreements for both licenses. Amounts estimated are adjusted to 2018 dollars. Department labor and other overhead costs associated with the activities required by the settlement agreements for the licenses are not included in the estimates.

Hydroelectric projects must satisfy the requirements of the Endangered Species Act (ESA) and the Clean Water Act in order to obtain a FERC license. ESA and related issues are discussed below.

Endangered Species—Several fish species that inhabit waters where hydroelectric projects are owned by the Department, or where the Department purchases power, have been listed under the ESA as threatened or endangered. Although the species were listed after FERC licenses were issued for all of the Department's hydroelectric projects, the ESA listings still affect operations of the Department's Boundary, Skagit, Tolt, and Cedar Falls hydroelectric projects.

Federal Regulations in response to the listing of species affect flow in the entire Columbia River system. As a result of these regulations, the Department's power generation at its Boundary Project is reduced in the fall and winter when the region experiences its highest sustained energy demand. The Boundary Project's firm capability is also reduced.

The Department, with the support of City Council, elected to take a proactive approach to address issues identified within the ESA. The Department is carrying out an ESA Early Action program in cooperation with agencies, tribes, local governments, and watershed groups for bull trout, Chinook salmon, and steelhead in the South Fork Tolt and Skagit Watersheds. The ESA Early Action program is authorized by City Council but is separate from any current FERC license requirements. The program includes habitat acquisition, management and restoration. The ESA Early Action has been successful in protecting listed species. Total costs for the Department's share of the Early Action program from inception in 1999 through December 31, 2018, are estimated to be $13.8 million, and $1.1 million has been allocated for the program in the 2019 budget.

Project Impact Payments—Effective August 2010, the Department renewed its contract with Pend Oreille County and committed to pay a total of $19.0 million over 10 years ending in 2019 to Pend Oreille County for impacts on county governments from the operations of the Department's hydroelectric projects. Effective February 2009, the Department renewed its contract with Whatcom County committing to pay a total of $15.8 million over 15 years ending in 2023. The payments compensate the counties, and certain school districts and towns located in these counties, for loss of revenues and additional financial burdens associated with the projects. The Boundary Project, located on the Pend Oreille River, affects Pend Oreille County, and Skagit River hydroelectric projects affect Whatcom County. The impact payments totaled $1.8 million to Pend Oreille County in 2018 and 2017, and $1.1 million to Whatcom County in 2018 and 2017.

Gamble v. City—A Department employee contends that the Department has failed to properly accommodate her disability. An adverse result in litigation could result in awards of back pay, compensatory damages, and attorneys' fees. Trial concluded on April 2017, with a verdict in favor of the Department. The plaintiff has appealed to the Washington Court of Appeals. The Department's ultimate liability is indeterminate.

Central Puget Sound Regional Transit Authority Condemnation Cases—The Department is a defendant in a series of condemnation actions by the Central Puget Sound Regional Transit Authority ("Sound Transit"). Sound Transit is working in concert with the City of Bellevue on multiple transportation projects which negatively affect the Department's East Side Lines transmission corridor, which is a 100 plus mile corridor between 150'-160' wide that runs contiguously from Maple Valley to City Light's Skagit Project in Skagit and Whatcom Counties. There are currently five condemnation actions for the specific area along 124th Street in Bellevue. The Department has contested Sound Transit's ability to condemn publicly owned property, but in each of the five condemnation actions, the trial courts determined that Sound Transit had demonstrated public use and necessity over portions of the Department's easement area. All of those decisions were appealed to the Washington Supreme Court. In August 2018, the Washington Supreme Court determined that although Sound Transit had authority to condemn the Department's property, the prior public use rule applied, and consequently remanded all five actions back to the trial court to determine whether the Department's existing public use was compatible with Sound Transit's proposed uses. The Parties have been in discussions towards resolving these issues, but the ultimate value and resolution of these matters is indeterminate.

Tao v. City—A Department employee alleges that she is a victim of discrimination on the basis of race, gender, and age. Employee also alleges that she has been retaliated against for engaging in protected activities opposing discrimination. Employee asserts that the Department failed to promote her and created a hostile work environment through, *inter alia*, investigating allegations of misconduct. An adverse result could include awards of back pay, compensatory damages, and attorneys' fees. The Department's ultimate liability is indeterminate.

Deformation Mitigation in N. Thomas Street—The Department is moving five 13.8 kV and 26kV feeders in Thomas Street at 6th Avenue to protect them for deformation caused by the tunneling activities, including the work necessary to extract the tunnel boring machine cutter head after reaching the North Portal. The Department anticipates that the total costs for this work is estimated at $3.1 million. City Light has requested that the Washington State Department of Transportation (WSDOT) reimburse it for those costs and has sent a proposed task order for that purpose, but to date, WSDOT has not agreed to reimburse the Department. The Department's ultimate recovery amount is unknown.

Denny Substation—The Department is building a new substation in the Denny Triangle neighborhood. The original contract price was $89.0 million. The general contractor filed claims against the Department totaling approximately $28.0 million based on changed conditions, unforeseen conditions, delays and schedule impacts alleged to be the Department's fault. The Department is contesting a majority of claimed amounts. The Department's ultimate liability is indeterminate.

Denny Network—The Department hired a general contractor to install an underground network in the South Lake Union neighborhood. The general contractor is in the process of preparing a claim for delay damages alleging that the Department is responsible for its cost overruns due to myriad factors. The claimed damages are expected to be approximately $20.0 million for a $48.0 million project. The Department's ultimate liability is indeterminate.

Other Contingencies—In addition to those noted above, in the normal course of business, the Department has various other legal claims and contingent matters outstanding. The Department believes that any ultimate liability arising from these actions will not have a material adverse impact on the Department's financial position, operations, or cash flows.

21. IMPLEMENTATION OF NEW ACCOUNTING STANDARDS

Implementation of GASB Statement No. 75 – The Department adopted the requirements of GASB Statement No. 75 *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* effective January 1, 2018. This statement provides guidance for the measurement and recognition of a net Other Postemployment Benefits (OPEB) liability and OPEB expense, including guidance for balances to be recognized as deferred outflows of resources and deferred inflows of resources. The impact of implementation for the Department was as follows:

Net OPEB liability – The net OPEB liability reported under GASB Statement No. 75 is the difference between the actuarial present value of projected OPEB benefit payments attributed to past periods of employee service and the OPEB plan's fiduciary net position. Previously, a liability was recognized only to the extent that contributions made to the plan were exceeded by the actuarially calculated contributions.

Deferred outflows of resources and deferred inflows of resources – GASB Statement No. 75 requires recognition of deferred outflows and inflows of resources associated with the difference between projected and actual earnings on plan investments, to be amortized to OPEB expense over a closed five-year period. Also to be recognized as deferred outflows and inflows of resources are differences between expected and actual experience with regard to economic or demographic factors in the measurement of the total OPEB liability and changes of assumptions about future economic or demographic changes or other inputs, to be amortized to OPEB expense over a closed period equal to the average of the expected remaining service lives of all employees that are provided with OPEB benefits through the OPEB plan. Employer contributions made between the net OPEB liability measurement date and the employer's fiscal year end are recognized as deferred outflows of resources, to be included in OPEB expense in the subsequent fiscal year.

The effect of adopting GASB Statement No. 75 on the Department's financial statements as of January 1, 2018 was as follows:

($ in millions)

	As Originally Reported December 31, 2017	GASB No. 75 balance January 01, 2018	Effects of Change
Balance Sheet			
Deferred Outflows of Resources			
Unrealized gains related to OPEB	$ -	$ 0.3	$ 0.3
Noncurrent Liabilities			
Net OPEB Liability	8.6	9.6	1.0
Net Position	1,337.9	1,337.2	(0.7)

*****

DEFINED BENEFIT PENSION PLAN

The Department's schedule of the employer's proportionate share of the net pension liability for the years ended December 31 (dollar amounts in millions):

	2018	2017	2016	2015
Employer's proportion of the net pension liability	21.00%	22.13%	24.46%	24.53%
Employer's proportionate share of total pension liability	$ 831.6	$ 839.5	$ 883.5	$ 841.5
Employer's proportionate share of plan fiduciary net position	$ 599.1	$ 550.7	$ 565.7	$ 569.7
Employer's proportionate share of the net pension liability	$ 232.5	$ 288.8	$ 317.8	$ 271.8
Employer's covered-employee payroll	$ 153.6	$ 156.5	$ 157.0	$ 152.3
Employer's proportionate share of net pension liability as a percentage of its covered-employee payroll	151.41%	184.49%	202.44%	178.48%
Plan fiduciary net position as a percentage of the total pension liability	72.04%	65.60%	64.03%	67.70%

Notes to Schedule

This schedule is intended to show information for 10 years. Since 2015 was the first year of this presentation, data on years preceding 2015 are not available. Additional years' data will be included as they become available.

For years 2015-2018, the annual investment rate or return underlying the calculation of total pension liability was assumed to be 7.50%. There were no changes to benefit terms or benefit assumptions in 2018. See Note 13 for details regarding actuarial methods and assumptions.

The Department's proportionate schedule of employer's contributions (dollar amounts in millions):

	2018	2017	2016	2015
Contractually required contribution	$ 24.7	$ 23.7	$ 25.3	$ 24.9
Contributions in relation to contractually required contribution	24.7	23.7	25.3	24.9
Contribution deficiency (excess)	$ -	$ -	$ -	$ -
Covered-employee payroll	$ 163.7	$ 153.6	$ 164.0	$ 165.0
Contributions as a percentage of covered-employee payroll	15.09%	15.43%	15.43%	15.09%

Notes to Schedule

This schedule is intended to show information for 10 years. Since 2015 was the first year of this presentation, data on years preceding 2015 are not available. Additional years' data will be included as they become available.

DEFINED BENEFIT OPEB PLAN

The Department's schedule of the employer's proportionate share of the net OPEB liability for the year ended December 31 (dollar amounts in millions):

	2018
Employer's proportion of the net OPEB liability	14.61%
Employer's proportionate share of total OPEB liability	$ 8.9
Employer's proportionate share of plan fiduciary net position	-
Employer's proportionate share of the net OPEB liability	$ 8.9
Employer's covered-employee payroll	$ 148.3
Employer's proportionate share of net OPEB liability as a percentage of its covered-employee payroll	6.02%
Plan fiduciary net position as a percentage of the total OPEB liability	-

Notes to Schedule
This schedule is intended to show information for 10 years. Since 2018 was the first year of this presentation, data on years preceding 2018 are not available. Additional years' data will be included as they become available.

There were no changes to benefit terms in 2018. See Note 14 for details regarding actuarial methods and assumptions under GASB 75.

Following are the disclosures for December 31, 2017 under GASB Statement No. 45, *Accounting and Financial Reporting by Employers for Postemployment Benefits Other than Pensions*.

SCHEDULES OF FUNDING PROGRESS

The Department's schedule of funding progress for the other post-employment benefit healthcare plans in accordance with GASB Statement No. 45 is presented below for the most recent actuarial valuation and the two preceding valuations for which the Department has available data (dollar amounts in millions):

Actuarial Valuation Date January 1	Actuarial Value of Assets (A)	Actuarial Accrued Liabilities (AAL) Entry Age (B)	Unfunded AAL (UAAL) (B-A)	Funding Ratio (A/B)	Covered Payroll (C)	UAAL as a Percentage of Covered Payroll ((B-A)/C)
2014	-	$ 41.8	$ 41.8	-	$ 1,004.0	4.2 %
2016	-	65.7	65.7	-	1,125.7	5.8

DEBT SERVICE COVERAGE

Following is a table that provides information for the Department's debt service coverage for years 2018, 2017, and 2016. The target level for debt service coverage was 1.8x on all bonds for 2018, 2017 and 2016 in accordance with current financial policies (which include a Rate Stabilization Account that will result in greater compliance of actual debt service coverage with the policy-specified level).

($ in millions)

Debt Service Coverage	December 31		
	2018	2017	2016
OPERATING REVENUES:			
Retail power revenues	$ 868.6	$ 875.2	$ 788.0
Short-term wholesale power revenues	61.0	60.9	62.9
Other power-related revenues (a)(b)(c)	45.9	35.8	32.6
Transfers from/(to) rate stabilization account (d)	(3.5)	(2.3)	(0.1)
Other operating revenues	19.6	20.1	19.8
Total operating revenues	$ 991.6	$ 989.7	$ 903.2
OPERATING EXPENSES:			
Long-term purchased power—Bonneville and other (b)	$ 217.8	$ 224.8	$ 219.8
Short-term wholesale power purchases	18.5	15.2	15.1
Other power expenses (b)	70.2	65.4	60.1
Transmission (e)	54.2	52.5	53.5
Distribution	61.9	60.4	63.5
Customer service	55.7	49.4	42.6
Conservation	32.9	32.5	30.2
Administrative and general	96.2	128.7	105.0
Taxes	91.8	94.8	85.2
Depreciation and amortization	124.0	128.8	120.8
Total operating expenses	$ 823.2	$ 852.5	$ 795.8
NET OPERATING REVENUE (f)	$ 168.4	$ 137.2	$ 107.4
Adjustments to Net Operating Revenue (g)			
City Taxes (h)	$ 53.4	$ 54.4	$ 48.4
Depreciation and amortization	124.0	128.8	120.8
Depreciation & amortization included in operating & maintenance expenses (i)	33.0	32.4	29.9
Pension expense (j)	22.0	37.1	40.8
Pension contributions (j)	(24.7)	(23.7)	(25.3)
Valuation on exchange power, net (b)(c)	0.9	-	-
BPA Conservation Augmentation/Agreement revenue (k)	(1.9)	(1.6)	(1.2)
Investment income (l)	10.9	7.4	7.3
Non-cash expenses (m)	0.8	2.4	1.8
Other (n)	1.6	2.4	2.0
Total adjustments	$ 220.0	$ 239.6	$ 224.5
Net Revenue Available for Debt Service	$ 388.4	$ 376.8	$ 331.9
Total Debt Service (o)	$ 212.4	$ 203.3	$ 196.5
Ratio of Available Net Revenue to Debt Service	1.83x	1.85x	1.69x

Notes

(a) Includes conservation and renewable credits under the power sales contract with BPA, the recognition of payments from BPA for the purchase of conservation savings, revenue from deliveries of power to Pend Oreille PUD pursuant to the Boundary Project's FERC license, and other energy credits.
(b) Effective January 1, 2016, the Department adopted GASB Statement No. 72, *Fair Value Measurement and Application.* Non-monetary transactions are measured at fair value and are valued at market. Disclosures required by GASB Statement No. 72 are available in Note 2 Fair Value Measurement.
(c) Includes significant activity for the valuation of energy delivered under seasonal exchanges, basis sales, and other power exchange contracts. Energy exchanges have both revenue and expense components; therefore, a net revenue or expense adjustment is made for a given year.
(d) Transfers from/(to) the RSA in accordance with Ordinance No. 123260, primarily to address fluctuations in surplus power sales.
(e) Includes revenue from the short-term sale of excess transmission capacity.
(f) Operating Income per audited financial statements.
(g) Significant non-cash transactions are adjusted from Net Operating Revenue to calculate Revenue Available for Debt Service. Furthermore, some types of revenue in addition to Operating Revenue are included to calculate Revenue Available for Debt Service. These adjustments are listed in the remaining lines within the table.
(h) City taxes are excluded because the lien on such taxes is junior to debt service in accordance with the Bond Legislation.
(i) The majority of the depreciation and amortization (non-cash) expenses included in Operating and Maintenance Expense are for amortization of conservation expenses that are recognized over a 20-year period.
(j) Pension expense is the amount recorded for compliance with GASB Statement No. 68, *Accounting and Financial Reporting for Pensions*, implemented in 2015, a non-cash item. Pension contributions are the Department cash contributions to the Seattle City Employee's Retirement System.
(k) Payments received for conservation measures are initially recorded as unearned revenue. The adjustment represents the amount of revenue amortized and recognized over future periods for financial reporting, a non-cash transaction.
(l) Investment income is not included in Total Revenue in this table; therefore, an adjustment is made to Net Operating Revenue, consisting primarily of interest earnings from City's cash pool and interest receipts from suburban underground charges. This amount excludes unrealized gains and losses, which are non-cash adjustments.
(m) Effective 2018 includes adjustment for GASB Statement No. 75, *Accounting and Financial Reporting for Postemployment Benefits Other Than Pensions* in addition to primarily claim expenses and capital projects expenditures from prior year which were determined not to be capital expenditures.
(n) Includes proceeds from sale of properties, principal receipts from suburban underground charges from local jurisdictions, and miscellaneous items.
(o) Net of federal bond subsidies.

DEBT SERVICE COVERAGE: ALL BONDS

Year Ending December 31 *($ in millions)*	Revenue Available for Debt Service	Debt Service Requirements	Debt Service Coverage
2018	$ 388.4	$ 212.4	1.83
2017	376.8	203.3	1.85
2016	331.9	196.5	1.69
2015	306.6	189.6	1.62
2014	341.4	184.8	1.85

INTEREST REQUIREMENTS AND PRINCIPAL REDEMPTION ON LONG-TERM DEBT

Year Ending December 31 *($ in millions)*	Fixed Rate Bonds			Variable Rate Bonds			
	Principal	Interest	Subtotal	Principal	Interest	Subtotal	Total [a]
2019	$ 116.5	$ 103.8	$ 220.3	$ 2.9	$ 4.1	$ 7.0	$ 227.3
2020	116.5	97.5	214.0	2.5	4.1	6.5	220.6
2021	116.0	92.1	208.1	2.1	4.0	6.1	214.2
2022	115.8	86.4	202.2	2.1	4.0	6.2	208.3
2023	118.1	80.5	198.6	2.2	3.9	6.2	204.7
2024	121.6	74.5	196.1	2.3	3.9	6.2	202.3
2025	111.4	68.4	179.8	2.4	3.8	6.2	186.0
2026	105.1	63.0	168.1	5.9	3.7	9.6	177.7
2027	80.0	58.2	138.2	6.1	3.6	9.7	147.9
2028	81.6	54.5	136.1	6.3	3.5	9.8	145.9
2029	75.5	50.9	126.4	6.6	3.3	9.9	136.3
2030	60.9	47.7	108.6	6.9	3.2	10.1	118.7
2031	63.2	45.0	108.2	7.2	3.1	10.2	118.5
2032	65.7	42.0	107.7	7.4	2.9	10.3	118.0
2033	68.3	39.0	107.3	7.7	2.8	10.5	117.8
2034	71.0	36.0	107.0	8.0	2.6	10.6	117.6
2035	73.8	33.0	106.8	8.4	2.4	10.8	117.6
2036	81.9	29.7	111.6	8.7	2.3	11.0	122.6
2037	71.4	26.2	97.6	9.1	2.0	11.1	108.7
2038	74.1	23.1	97.2	9.4	1.9	11.3	108.5
2039	76.9	19.9	96.8	9.8	1.7	11.5	108.3
2040	79.8	16.5	96.3	10.2	1.5	11.7	108.0
2041	68.9	13.4	82.3	10.7	1.2	11.9	94.2
2042	54.9	11.0	65.9	11.1	1.0	12.1	78.0
2043	57.2	8.6	65.8	11.5	0.8	12.3	78.1
2044	48.6	6.3	54.9	12.0	0.5	12.5	67.4
2045	41.3	4.4	45.7	12.5	0.3	12.8	58.5
2046	34.7	2.8	37.5	5.5	0.1	5.6	43.1
2047	28.4	1.4	29.8	-	-	-	29.8
2048	15.0	0.3	15.3	-	-	-	15.3
Total	$ 2,294.1	$ 1,236.1	$ 3,530.2	$ 197.5	$ 72.2	$ 269.7	$ 3,799.9

[a] Maximum debt service of $227.3 is due in 2019. See Note 9 Long-term debt.
Note: All parity bonds of the Department are fixed rate bonds except the 2018B and 2018C bonds which are variable rate bonds.

STATEMENT OF LONG-TERM DEBT

As of December 31, 2018

($ in millions)

Bond Series	When Due	Interest Rate (%)	Amount Issued	Amount Outstanding	Amount Due Within One Year	Accrued Interest
Series 2008	2019-2020	5.250	$ 20.6	$ 10.0	$ 10.0	$ 0.1
Series 2010A	2019-2021	4.447	4.6	4.6	0.0	0.1
Series 2010A	2022	4.597	7.2	7.2	0.0	0.1
Series 2010A	2023	4.747	7.5	7.5	0.0	0.1
Series 2010A	2024	4.947	7.7	7.7	0.0	0.2
Series 2010A	2025	5.047	8.0	8.0	0.0	0.2
Series 2010A	2026	5.147	8.2	8.2	0.0	0.2
Series 2010A	2027	5.247	8.5	8.5	0.0	0.2
Series 2010A	2028-2030	5.470	27.4	27.4	0.0	0.6
Series 2010A	2031-2040	5.570	102.6	102.5	0.0	2.4
Series 2010B	2019	4.000	1.5	1.5	1.5	0.0
Series 2010B	2019	5.000	42.7	42.7	42.7	0.9
Series 2010B	2020	4.000	2.6	2.6	0.0	0.0
Series 2010B	2020	5.000	43.9	43.9	0.0	0.9
Series 2010B	2021-2026	5.000	187.8	155.9	0.0	3.3
Series 2010C	2019-2040	5.590	13.3	13.3	0.0	0.3
Series 2011A	2031-2036	5.250	75.8	69.3	11.4	1.4
Series 2011B	2027	5.750	10.0	10.0	0.0	0.2
Series 2012A	2019-2027	5.000	198.0	139.1	13.2	0.5
Series 2012A	2028	3.250	12.4	12.4	0.0	0.1
Series 2012A	2034-2036	4.000	25.1	25.1	0.0	0.1
Series 2012A	2037-2041	4.000	49.1	49.1	0.0	0.2
Series 2012C	2028	3.400	4.3	4.3	0.0	-
Series 2012C	2029	3.500	7.7	7.7	0.0	-
Series 2012C	2030	3.500	7.7	7.7	0.0	-
Series 2012C	2031-2033	3.750	23.4	23.4	0.0	0.1
Series 2013	2019-2033	5.000	97.4	88.0	3.5	2.1
Series 2013	2034-2035	4.000	14.7	14.7	0.0	0.3
Series 2013	2036-2038	4.125	24.4	24.4	0.0	0.6
Series 2013	2039-2043	4.500	48.3	48.3	0.0	1.1
Series 2014	2019-2029	5.000	163.2	114.4	18.1	1.8
Series 2014	2030-2038	4.000	53.9	53.9	0.0	0.8
Series 2014	2039-2040	4.000	14.8	14.8	0.0	0.2
Series 2014	2041-2044	4.000	33.3	33.3	0.0	0.5
Series 2015A	2019-2026	5.000	62.9	45.9	6.0	0.3
Series 2015A	2027-2045	4.000	109.0	109.0	0.0	0.8
Series 2016A	2036-2041	4.050	31.9	31.9	0.0	0.6
Series 2016B	2020-2028	5.000	103.0	101.5	0.0	1.2
Series 2016B	2029	4.000	13.9	13.9	0.0	0.2
Series 2016C	2019-2026	5.000	56.9	52.6	2.4	0.5
Series 2016C	2027-2046	4.000	103.9	103.9	0.0	1.2
Series 2017C	2019-2032	5.000	174.2	169.1	4.1	2.5
Series 2017C	2033-2047	4.000	211.3	211.3	0.0	3.1
Series 2018A	2019-2029	5.000	60.2	60.2	3.9	1.3
Series 2018A	2030-2048	4.000	203.6	203.6	0.0	4.6
Series 2018B B.1	2026-2045	1.77 - 2.00 ^	50.1	50.1	0.0	0.1
Series 2018B B.2	2026-2045	1.77 - 2.00 ^	50.1	50.1	0.0	0.1
Series 2018C C.1	2019-2046	1.63 - 2.20 ^	49.3	48.6	1.4	0.1
Series 2018C C.2	2019-2046	1.63 - 2.20 ^	49.3	48.6	1.4	0.1
Total			$ 2,687.2	$ 2,491.6	$ 119.4	$ 36.4

^ Range of adjustable rates in effect during 2018.

Note: All parity bonds of the Department are fixed rate bonds except the 2018B B.1&B.2, and 2018C C.1&C.2 bonds, which are variable rate bonds.

POWER COSTS AND STATISTICS

Year ending December 31 *($ in millions)*	2018	2017	2016	2015	2014
POWER COSTS					
Hydroelectric generation(a)(c)(f)	$ 51.7	$ 56.8	$ 53.0	$ 50.1	$ 49.9
Long-term purchased power(b)	217.8	224.8	219.8	213.6	214.3
Wholesale power purchases(c)(e)	18.5	15.2	15.1	26.8	14.9
Fair valuation & other power purchases(b)(e)	20.6	11.4	10.5	11.8	17.7
Owned transmission(a)(f)	17.0	15.5	15.9	17.2	15.3
Wheeling expenses	43.2	42.9	42.9	42.0	42.1
Other power expenses	13.1	13.9	12.8	12.9	13.2
Total power costs(f)	381.9	380.5	370.0	374.4	367.4
Less short-term wholesale power sales(c)	(61.0)	(60.9)	(62.9)	(61.2)	(96.8)
Less other power-related revenues	(28.5)	(20.8)	(16.7)	(19.9)	(25.5)
Less fair valuation other power-related(b)	(17.4)	(15.0)	(15.9)	(16.9)	(25.3)
Net power costs(f)	$ 275.0	$ 283.8	$ 274.5	$ 276.4	$ 219.8
POWER STATISTICS (MWh)					
Hydroelectric generation(c)	6,419,136	6,396,563	6,707,264	5,979,884	7,091,368
Long-term purchased power(b)	6,354,303	7,521,767	7,215,308	6,900,647	6,658,689
Wholesale power purchases(c)(e)	1,167,441	904,362	936,289	1,379,168	900,527
Wholesale power sales(c)(e)	(3,329,288)	(3,695,173)	(4,044,452)	(3,548,507)	(4,083,391)
Other(d)	(938,363)	(1,154,419)	(1,117,826)	(1,023,970)	(655,569)
Total power available	9,673,229	9,973,100	9,696,583	9,687,222	9,911,624
Less self consumed energy	(25,642)	(26,691)	(24,912)	(25,195)	(29,717)
Less system losses	(573,525)	(537,750)	(491,233)	(504,533)	(541,323)
Total power delivered to retail customers	9,074,062	9,408,659	9,180,438	9,157,494	9,340,584
Net power cost per MWh delivered(f)	$ 30.31	$ 30.16	$ 29.90	$ 30.18	$ 23.53

(a) Including depreciation.
(b) Long-term purchased power, fair valuation & other power purchases, and fair valuation other power-related include energy exchanged under seasonal and other exchange contracts are valued at market. Disclosures required by GASB Statement No. 72, Fair Value *Measurement and Application, are available in Note 2 Fair Value Measurements.*
(c) The level of generation (and consequently the amount of power purchased and sold on the wholesale market) can fluctuate widely from year to year depending upon water conditions in the Northwest region.
(d) "Other" includes seasonal exchange power delivered and miscellaneous power transactions.
(e) Bookout purchases are excluded from wholesale power purchases and are reported on a net basis in wholesale power sales, however MWh are presented gross.
(f) 2017 revised for proper allocation of Hydroelectric generation and Owned transmission depreciation costs.

HISTORICAL ENERGY RESOURCES (in MWh)

	2018	2017	2016	2015	2014
Department-Owned Generation					
Boundary Project	4,008,235	3,825,302	3,888,316	3,469,855	4,249,957
Skagit Hydroelectric Project:					-
Gorge	947,000	998,676	1,036,540	953,628	1,057,865
Diablo	626,127	692,828	870,216	775,025	857,757
Ross	690,006	741,493	791,415	684,687	796,513
Cedar Falls/Newhalem	89,250	83,461	68,429	47,571	65,687
South Fork Tolt	58,518	54,803	52,348	49,118	63,589
Subtotal	6,419,136	6,396,563	6,707,264	5,979,884	7,091,368
Energy Purchases					
Bonneville	4,435,838	5,482,904	5,138,417	4,971,459	5,155,271
Priest Rapids	25,732	24,532	25,249	23,698	21,961
Columbia Basin Hydropower	241,236	228,789	253,628	258,678	272,842
High Ross	310,700	313,973	308,478	310,102	307,873
Lucky Peak	347,669	463,403	340,474	278,001	308,334
Stateline Wind Project	342,873	330,161	373,389	299,551	357,325
Columbia Ridge	102,617	96,096	99,487	94,271	68,920
Seasonal and Other Exchange(a)	547,638	581,909	676,186	664,887	411,555
Wholesale Market Purchases(b)	1,167,441	904,362	936,289	1,379,168	900,527
Subtotal	7,521,744	8,426,129	8,151,597	8,279,815	7,804,608
Total Department Resources	13,940,880	14,822,692	14,858,861	14,259,699	14,895,976
Minus Offsetting Energy Sales					
Firm Energy Sales and Marketing Losses(c)	344,435	328,666	344,383	331,897	393,844
Seasonal and Other Exchange(a)	593,928	825,753	773,443	692,073	507,117
Wholesale Market Sales	3,329,288	3,695,173	4,044,452	3,548,507	4,083,391
Total Energy Resources	9,673,229	9,973,100	9,696,583	9,687,222	9,911,624

(a) Includes exchange contracts with the Northern California Power Authority (NCPA), Sacramento Municipal Utility District (SMUD), Grant County and the Lucky Peak Project.

(b) Purchases to compensate for low water conditions and to balance loads and resources.

(c) Energy provided to Public Utility District of Pend Oreille County under the Boundary Project's FERC license and include incremental losses due to expanded activity in the wholesale market.

CUSTOMER STATISTICS

Years ended December 31,		2018		2017		2016		2015		2014
Average number of customers:										
Residential		410,664		403,888		397,074		381,419		374,619
Non-residential		50,859		50,608		50,258		41,391		40,437
Total		461,523		454,496		447,332		422,810		415,056
Megawatt-hours[(a)]:										
Residential	33%	2,992,914	33%	3,132,079	32%	2,917,984	32%	2,914,563	32%	2,987,711
Non-residential	67%	6,081,148	67%	6,276,580	68%	6,262,454	68%	6,242,931	68%	6,352,873
Total	100%	9,074,062	100%	9,408,659	100%	9,180,438	100%	9,157,494	100%	9,340,584
Average annual revenue per customer[(a)]:										
Residential	$	778	$	812	$	717	$	691	$	695
Non-residential	$	10,748	$	10,757	$	9,983	$	11,390	$	11,448

* Seattle City Light changed customer counts to Service Agreement effective September 2016 with the implementation of the new retail electric billing system. Service Agreement determines how Seattle City Light and Seattle Public Utilities charge customers for services provided. An account can have several Service Agreements for the different types of services. No revisions were made to prior year customer counts.

Years ended December 31,		2018	2017	2016	2015	2014
Average annual consumption per customer (kWhs)[(a)(b)]:						
Residential	- Seattle	7,288	7,755	7,349	7,641	7,975
	- National	n/a	n/a	10,766	10,816	10,936
Non-residential	- Seattle	119,568	124,018	124,606	150,828	157,107
	- National	n/a	n/a	124,518	125,592	126,114
Average rate per kilowatt-hour (cents)[(a)(b)]:						
Residential	- Seattle	10.67	10.47	9.75	9.05	8.71
	- National	n/a	n/a	12.55	12.65	12.52
Non-residential	- Seattle	8.99	8.67	8.01	7.55	7.29
	- National	n/a	n/a	8.91	9.08	9.2

(a) Source of national data: Department of Energy (www.eia.doe.gov/electricity/annual/). 2018 National average annual consumption data and average rate data not available. Certain 2017-2014 national average annual consumption and national average rate data were updated with revised actuals.

(b) Seattle amounts include an allocation for the net change in unbilled revenue. Unbilled revenue excludes retail customer voluntary payments for conservation and solar energy as well as revenue from diverted electricity.

NOTE 1: A comprehensive rate change of 5.6% became effective January 1, 2018.

NOTE 2: A Rate Stabilization Account (RSA) surcharge of 1.5% is currently in effect to all residential and non-residential rates schedules.

NOTE 3: Notice of public hearings on future rate actions may be obtained on request to:

The Office of the City Clerk, 600-4th Ave, Floor Three, Seattle, WA 98104. Phone number 206-684-8344.

Additional information about city of Seattle Council meetings can be found on the Web at www.seattle.gov/council/calendar.

HIGHLIGHTS *(Unaudited)*

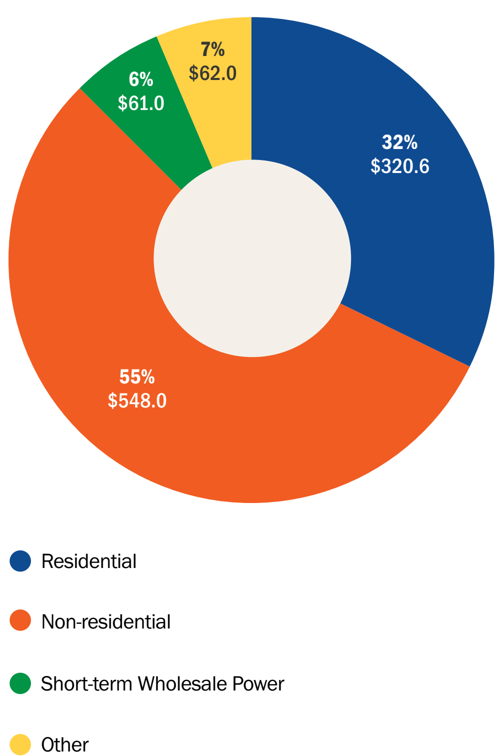
FINANCIAL *($ in millions)*		**2018**		**2017**	**% Change**
Total operating revenues	$	991.6	$	989.7	0.2
Total operating expenses		823.2		852.5	(3.4)
Operating income		168.4		137.2	22.7
Investment income		10.7		6.8	57.4
Interest expense, net		(83.4)		(75.4)	10.6
Noncapital grants		0.7		(0.3)	(333.3)
Other income, net		6.2		6.8	(8.8)
Capital contributions and grants		59.6		45.3	31.6
Change in net position	$	162.2	$	120.4	34.7
Debt service coverage ratio		1.83x		1.85x	(1.1)

ENERGY	**2018**	**2017**	**% Change**
Total generation *(City Light-owned generation)*	6,419,136 MWh	6,396,563 MWh	0.4
System load	9,673,229 MWh	9,973,100 MWh	(3.0)
Peak load (highest single hourly use)	1,764 MW (February 23, 2018)	1,870 MW (January 04, 2017)	(5.7)
Average number of residential and non-residential customers	461,523	454,496	1.5
Average annual residential and non-residential energy consumption (includes estimated unbilled revenue allocation)	126,856 kWh	131,773 kWh	(3.7)

MWh = Megawatt–hour(s)   MW = Megawatt(s)   kWh = Kilowatt–hour(s)

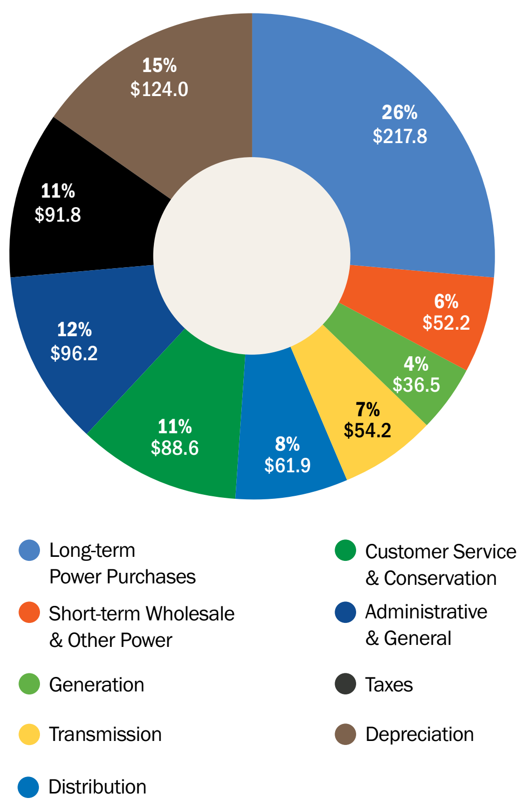
2018 OPERATING REVENUES

(IN MILLIONS = $991.6)



2018 OPERATING EXPENSES

(IN MILLIONS = $823.2)



FINANCIAL SUMMARY *(Unaudited)*

($ in millions)

Years ended December 31,	2018	2017	2016	2015	2014
BALANCE SHEETS [A]					
Assets and Deferred Outflows of Resources					
Utility plant, net	$ 3,820.8	$ 3,509.5	$ 3,214.7	$ 2,961.5	$ 2,728.3
Restricted assets	263.7	252.4	222.0	265.1	298.4
Current assets	374.0	343.6	286.5	339.6	298.8
Other assets	432.0	416.8	396.2	339.5	319.7
Deferred outflows of resources	57.9	83.2	94.9	49.8	19.3
Total assets and deferred outflows of resources	$ 4,948.4	$ 4,605.5	$ 4,214.3	$ 3,955.5	$ 3,664.5
Liabilities, Deferred Inflows of Resources, & Net Position					
Long-term debt, net	$ 2,564.9	$ 2,417.4	$ 2,165.3	$ 2,090.8	$ 1,925.2
Noncurrent liabilities	365.8	409.6	433.6	341.5	67.3
Current liabilities	316.6	280.7	266.5	271.4	258.3
Other liabilities	37.8	36.3	37.2	29.7	26.7
Deferred inflows of resources	163.9	123.6	94.2	89.9	111.5
Net position [B, C]	1,499.4	1,337.9	1,217.5	1,132.2	1,275.5
Total liabilities, deferred inflows of resources, & net position	$ 4,948.4	$ 4,605.5	$ 4,214.3	$ 3,955.5	$ 3,664.5
STATEMENTS OF REVENUES AND EXPENSES [A]					
Operating Revenues					
Residential	$ 327.9	$ 324.3	$ 285.1	$ 260.0	$ 268.0
Non-residential	555.4	538.1	496.8	470.7	467.0
Unbilled revenue - net change	(14.7)	12.8	6.1	5.9	(14.2)
Total retail power revenues	868.6	875.2	788.0	736.6	720.8
Short-term wholesale power revenues	61.0	60.9	62.9	61.2	96.8
Other power-related revenues	45.9	35.8	32.6	36.8	50.8
Transfers from/(to) rate stabilization account	(3.5)	(2.3)	(0.1)	23.4	(4.4)
Other revenues	19.6	20.1	19.8	24.9	22.4
Total operating revenues	991.6	989.7	903.2	882.9	886.4
Operating Expenses					
Long-term purchased power	217.8	224.8	219.8	213.6	214.3
Short-term wholesale power purchases	18.5	15.2	15.1	26.8	14.9
Other power expenses	33.7	25.3	23.3	24.8	30.9
Generation	36.5	40.1	36.8	34.8	35.0
Transmission	54.2	52.5	53.5	54.3	52.8
Distribution	61.9	60.4	63.5	65.1	59.7
Customer service	55.7	49.4	42.6	38.3	37.6
Conservation	32.9	32.5	30.2	29.1	27.3
Administrative and general	96.2	128.7	105.0	92.1	75.8
Taxes	91.8	94.8	85.2	81.1	80.0
Depreciation and amortization	124.0	128.8	120.8	112.0	105.8
Total operating expenses	823.2	852.5	795.8	772.0	734.1
Operating income	168.4	137.2	107.4	110.9	152.3
Noncapital grants	0.7	(0.3)	2.5	4.6	3.8
Other income, net	6.2	6.8	6.1	5.9	6.8
Investment income	10.7	6.8	6.0	6.2	7.9
Total operating and other income	186.0	150.5	122.0	127.6	170.8
Interest Expense					
Interest expense	102.1	94.4	93.5	93.4	89.6
Amortization of debt expense	(6.6)	(7.0)	(8.2)	(8.0)	(5.9)
Interest charged to construction	(12.1)	(12.0)	(10.2)	(8.9)	(5.8)
Net interest expense	83.4	75.4	75.1	76.5	77.9
Capital Contributions and Grants	59.6	45.3	38.4	39.4	28.4
Change in net position	$ 162.2	$ 120.4	$ 85.3	$ 90.5	$ 121.3

[A] Effective January 1, 2014, the Department adopted Statement No. 65 of the GASB, *Items Previously Reported as Assets and Liabilities.* Accordingly, certain items previously reported as assets and liabilities are reclassified as deferred outflows of resources or deferred inflows of resources, and recognize as expense certain items previously reported as assets.

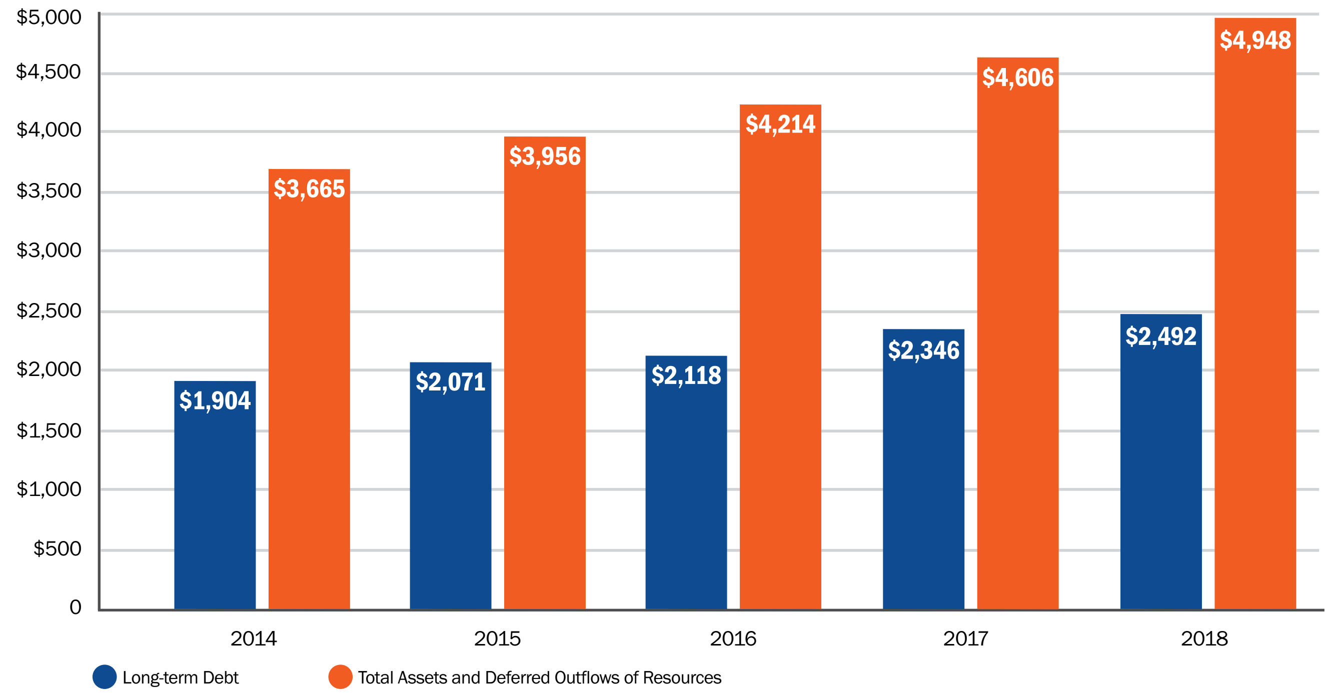
[B] Net Position for 2015 includes a beginning of the year adjustment for the implementation of Statement No. 68 of the GASB, *Accounting and Financial Reporting for Pensions.* See the audited financial statements and accompanying notes.

[C] Net Position for 2018 includes a beginning of the year adjustment for the implementation of Statement No. 75 of the GASB, *Accounting and Financial Reporting for Postemployment Benefits Other than Pensions.* See the audited financial statements and accompanying notes.

LONG-TERM DEBT *(Unaudited)*

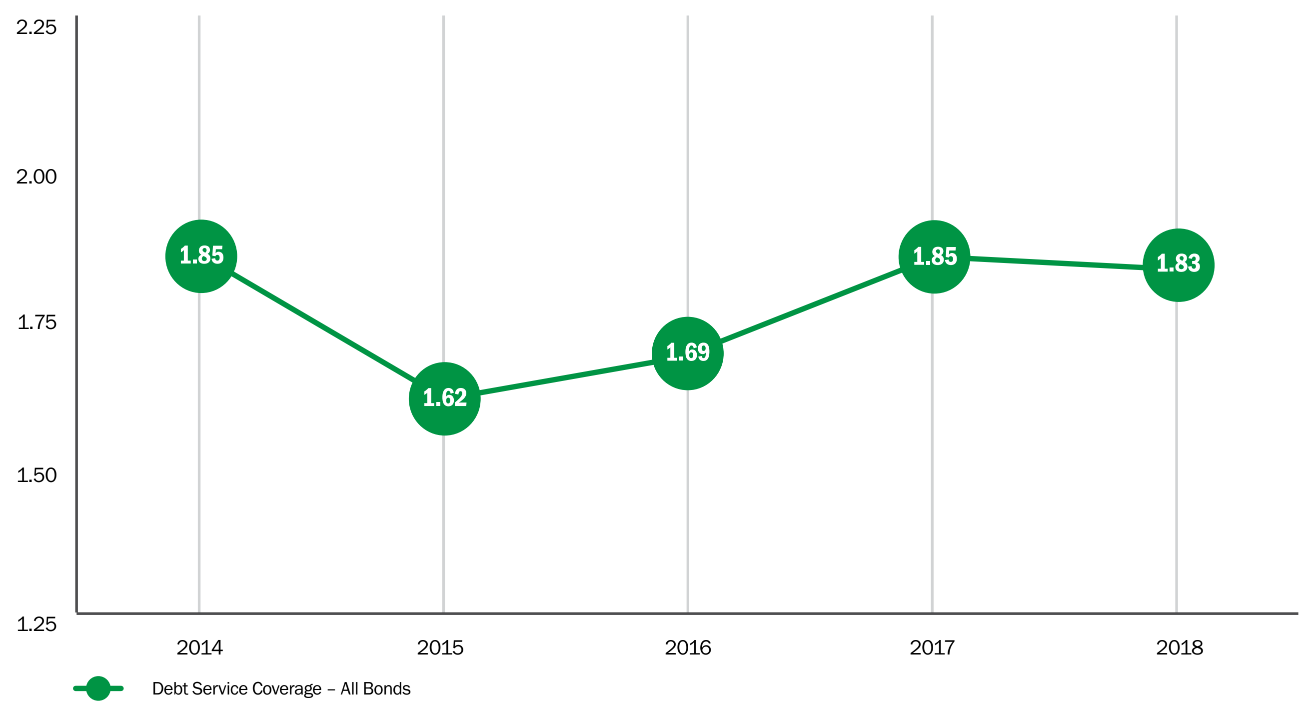
LONG-TERM DEBT & TOTAL ASSETS AND DEFERRED OUTFLOWS OF RESOURCES

(IN MILLIONS)



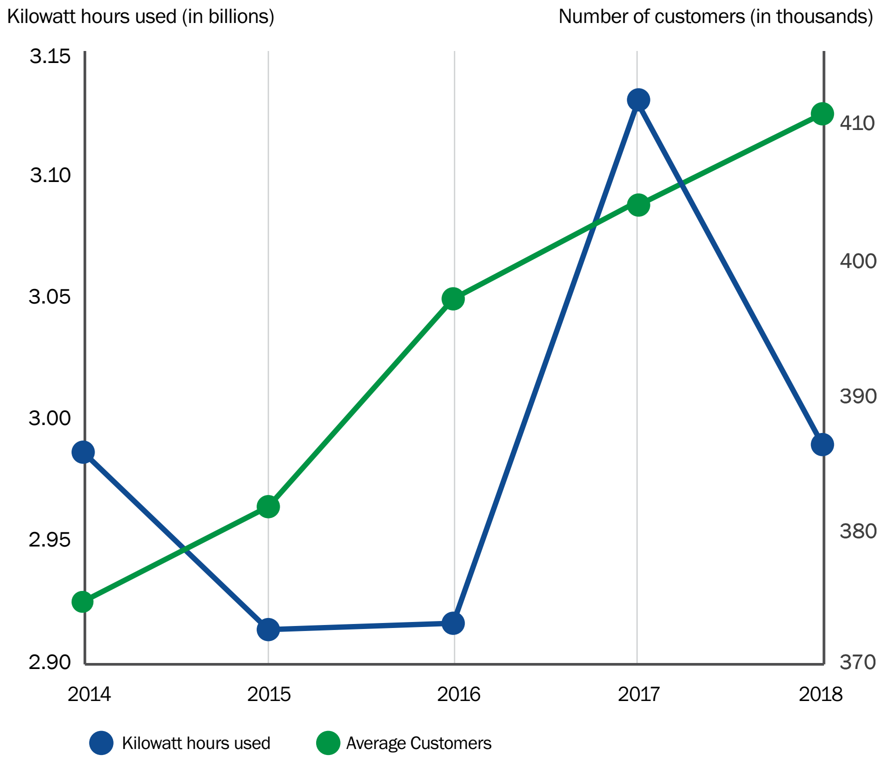
DEBT SERVICE COVERAGE 2014-2018

(times covered)



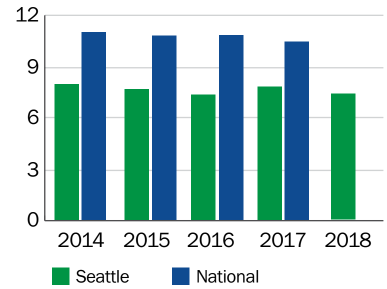
CUSTOMER STATISTICS *(Unaudited)*

RESIDENTIAL CONSUMPTION



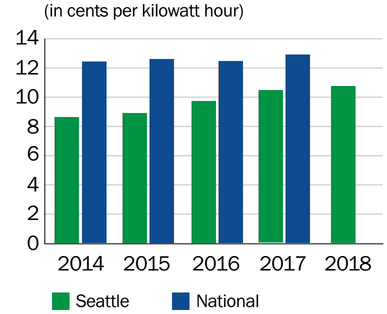
AVERAGE ANNUAL RESIDENTIAL CONSUMPTION

(in thousands of kilowatt hours)

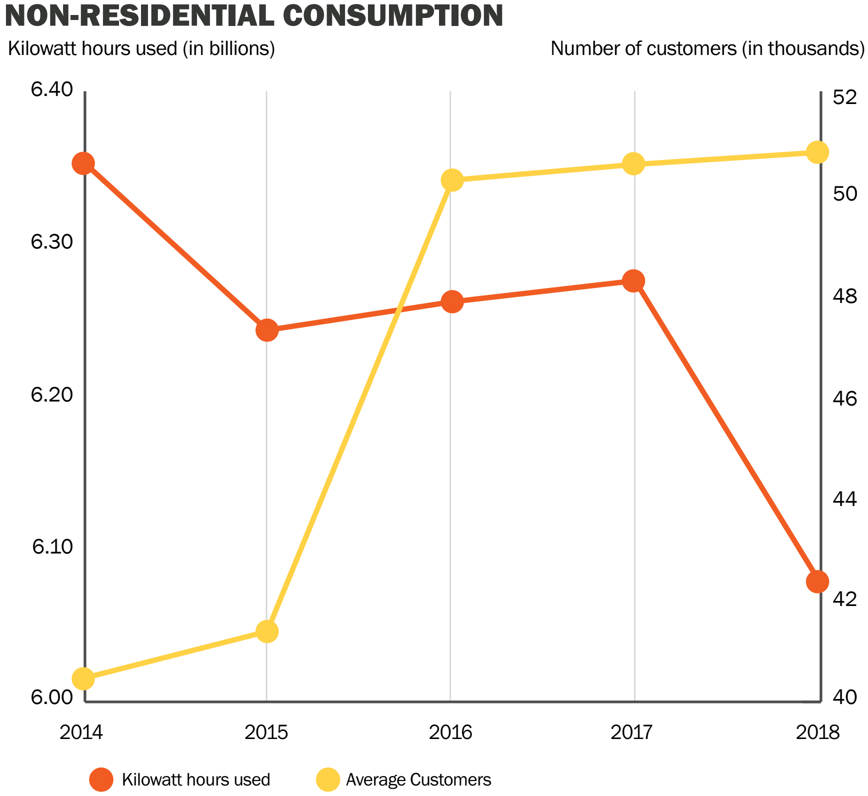


AVERAGE RESIDENTIAL RATES

(in cents per kilowatt hour)

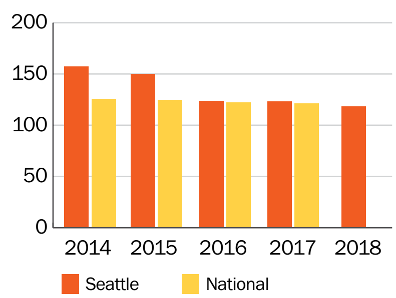


NON-RESIDENTIAL CONSUMPTION



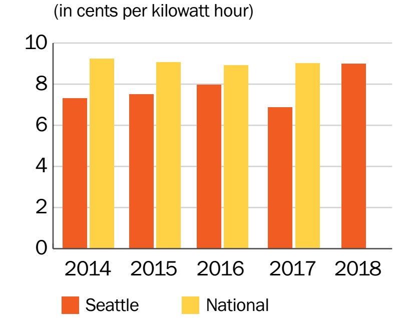
AVERAGE ANNUAL NON–RESIDENTIAL CONSUMPTION

(in thousands of kilowatt hours)



AVERAGE NON–RESIDENTIAL RATES

(in cents per kilowatt hour)



Note: Source of national data: Department of Energy (www.eia.doe.gov/electricity/annual/). 2018 National average annual consumption data and average rate data not available; Certain 2015-2014 National average annual consumption and National average rate data were updated with revised actuals.

POWER *(Unaudited)*

2018 SOURCES OF POWER

(in percent megawatt hours)

GENERATED

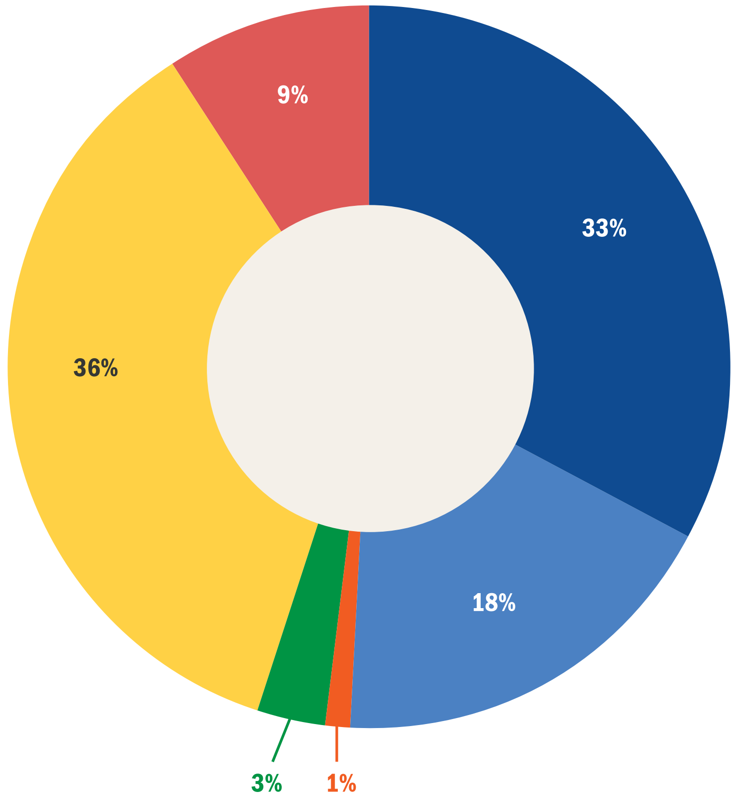
- Boundary
- Skagit
- Cedar Falls & South Fork Tolt

TREATY

- BC Hydro

PURCHASED

- BPA
- Other



2018 USES OF POWER

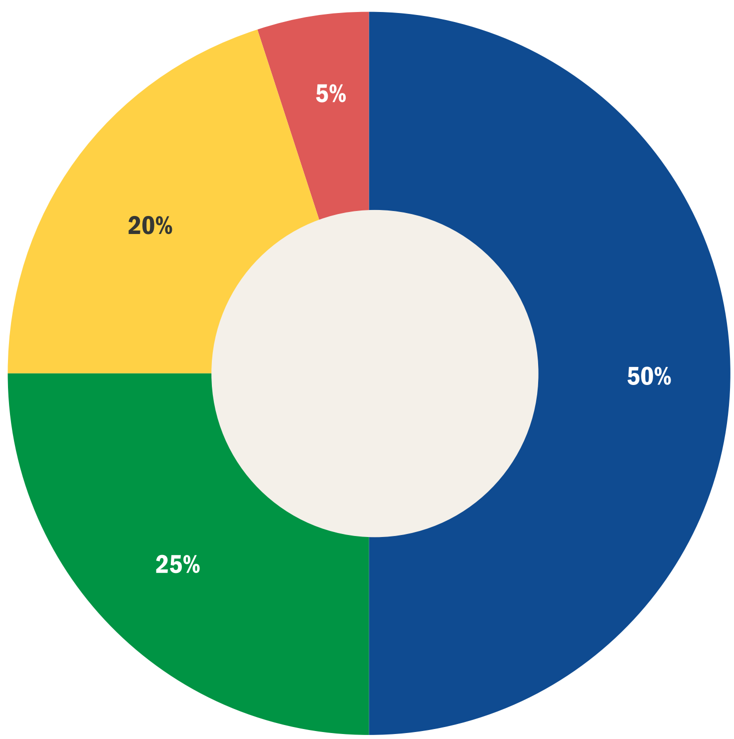
(in percent megawatt hours)

SERVICES

- Non–residential
- Residential

OTHER

- Wholesale & Other
- Seattle City Light Operations/Losses



SYSTEM CAPABILITY & REQUIREMENTS *(Unaudited)*

CHANGES IN OWNED TOTAL GENERATING INSTALLED CAPABILITY *(in Kilowatts)*

Year	Plant	Change in Capability	Total [A] Capability
1904-09	Cedar Falls Hydro Units 1, 2, 3 & 4	10,400	10,400
1912	Lake Union Hydro Unit 10	1,500	11,900
1914-21	Lake Union Steam Units 11, 12 & 13	40,000	51,900
1921	Newhalem Hydro Unit 20	2,000	53,900
1921	Cedar Falls Hydro Unit 5	15,000	68,900
1924-29	Gorge Hydro Units 21, 22 & 23	60,000	128,900
1929	Cedar Falls Hydro Unit 6	15,000	143,900
1932	Cedar Falls Hydro Units 1, 2, 3 & 4	(10,400)	133,500
1932	Lake Union Hydro Unit 10	(1,500)	132,000
1936-37	Diablo Hydro Units 31, 32, 35 & 36	155,400	287,400
1951	Georgetown Steam Units 1, 2 & 3	21,000	308,400
1951	Gorge Hydro Unit 24	64,900	373,300
1952-56	Ross Hydro Units 41, 42, 43 & 44	450,000	823,300
1958	Diablo Plant Modernization	35,000	858,300
1961	Gorge Hydro, High Dam	46,000	904,300
1967	Georgetown Plant, performance test gain	2,000	906,300
1967	Boundary Hydro Units 51, 52, 53 & 54	639,400	1,545,700
1972	Centralia Units 1 & 2	102,400	1,648,100
1980	Georgetown Steam Units 1, 2, & 3	(23,000)	1,625,100
1986	Boundary Hydro Units 55 & 56	400,000	2,025,100
1987	Lake Union Steam Units 11, 12 & 13	(40,000)	1,985,100
1989-92	Gorge Units 21, 22, & 23, new runners	4,600	1,989,700
1990	Gorge Unit 24	32,000	2,021,700
1993	Centralia Transmission Upgrade	5,000	2,026,700
1995	South Fork Tolt Unit 81	16,800	2,043,500
2000	Centralia Units 1 & 2	(107,400)	1,936,100
2013-2014	Boundary Hydro Units 53 & 55 rewind	39,000	1,975,100
2015	Boundary Hydro Unit 56 upgrade	39,000	2,014,100
2017	Ross Hydro Unit 42 changeout	15,000	2,029,100
2017	Boundary Hydro Unit 55 upgrade	29,000	2,058,100
2018	Diablo Unit 31 Overhaul	(4,000)	2,054,100
2018	Boundary Hydro Unit 56 upgrade	29,000	2,083,100

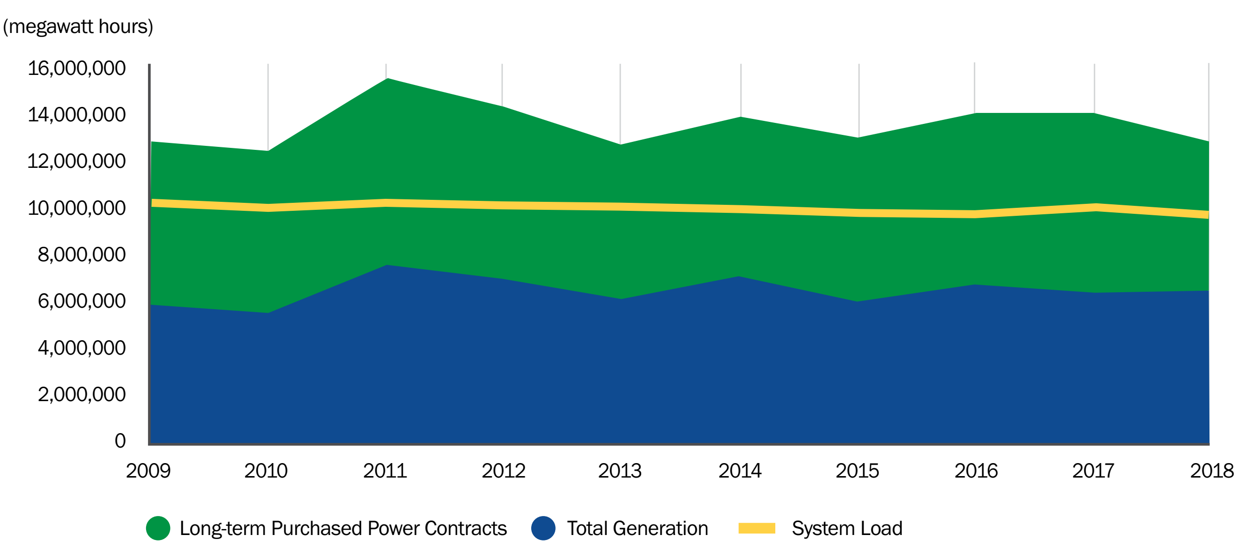
[A] Capability is the maximum capability of generators and associated prime movers expressed in kW.

SYSTEM REQUIREMENTS
(in Kilowatts)

Year	Average Load	Peak Load [B]
1950	154,030	312,000
1955	381,517	733,000
1960	512,787	889,000
1965	635,275	1,138,000
1970	806,813	1,383,000
1975	848,805	1,429,387
1980	963,686	1,771,550
1985	1,025,898	1,806,341
1990	1,088,077	2,059,566
1995	1,072,692	1,748,657
2000	1,142,383	1,769,440
2005	1,113,513	1,719,020
2006	1,149,380	1,825,819
2007	1,171,596	1,777,096
2008	1,181,325	1,904,735
2009	1,162,375	1,859,875
2010	1,131,365	1,846,708
2011	1,164,725	1,748,833
2012	1,147,771	1,804,708
2013	1,147,112	1,840,792
2014	1,131,464	1,866,792
2015	1,105,847	1,689,000
2016	1,103,892	1,785,000
2017	1,138,482	1,870,000
2018	1,104,250	1,764,000

[B] Peak Load (highest single hourly use).

TOTAL GENERATION AND LONG-TERM PURCHASED POWER CONTRACTS VS. SYSTEM LOAD



TAXES & CONTRIBUTIONS *(Unaudited)*

TAXES AND CONTRIBUTIONS BY SEATTLE CITY LIGHT TO THE COST OF GOVERNMENT

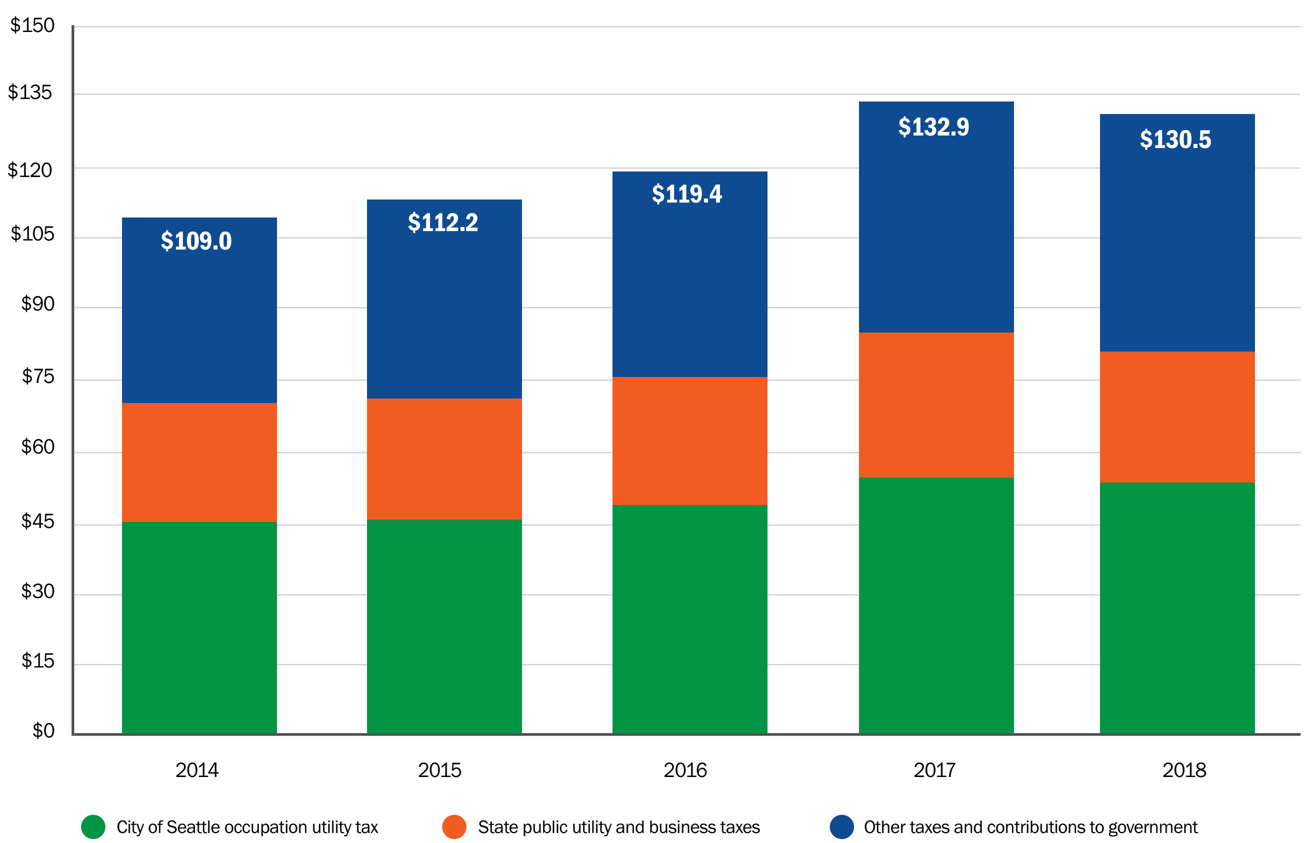
(in millions)

Years ended December 31,	2018	2017	2016	2015	2014
Taxes					
City of Seattle occupation utility tax	$ 53.4	$ 54.4	$ 48.4	$ 45.5	$ 44.6
State public utility and business taxes	27.4	30.2	27.1	25.5	25.7
Suburban contract payments and other	6.3	6.4	6.0	5.9	5.6
Contract payments for government services	4.6	3.8	3.7	4.3	4.1
Total taxes as shown in statement of revenues and expenses	91.7	94.8	85.2	81.2	80.0
Taxes/licenses charged to accounts other than taxes	16.6	15.4	16.6	15.6	16.0
Other contributions to the cost of government	22.2	22.7	17.6	15.4	13.0
Total miscellaneous taxes	38.8	38.1	34.2	31.0	29.0
Total taxes and contributions	$ 130.5	$ 132.9	$ 119.4	$ 112.2	$ 109.0

Note 1: Electric rates include all taxes. The State Public Utility Tax rate for retail electric power sales was 3.8734%. The City of Seattle Occupation Utility Tax rate was 6% for in-state retail electric power sales.
Note 2: 2017 Taxes/licenses charged to accounts other than taxes updated with more recent information.

TAXES AND CONTRIBUTIONS TO THE COST OF GOVERNMENT

(in millions)



EXPENDITURES & SAVINGS *(Unaudited)*

PUBLIC PURPOSE EXPENDITURES

(in millions)

Years ended December 31,	2018	2017	2016	2015	2014
CONSERVATION					
Annual energy savings (megawatt hours) [A]	131,858	136,632	133,532	156,911	186,516
Programmatic conservation expenses [B]					
Non-low income	$ 24.3	$ 31.0	$ 31.3	$ 32.6	$ 32.8
Low income	1.7	2.9	2.8	2.3	1.9
Non-programmatic conservation expenses [C]	11.5	12.6	11.2	8.8	7.8
Subtotal	37.5	46.5	45.3	43.7	42.5
OTHER PUBLIC PURPOSE EXPENDITURES					
Low-income energy assistance [D]	17.8	18.5	13.4	9.9	9.5
Non-hydro renewable resources [E]	33.7	32.9	36.3	29.5	30.8
Subtotal	51.5	51.4	49.7	39.4	40.3
NET PUBLIC PURPOSE SPENDING	89.0	97.9	95.0	83.1	82.8
Revenue from retail electric sales	$ 868.6	$ 875.2	$ 788.0	$ 736.6	$ 720.8
PERCENT PUBLIC PURPOSE SPENDING TO RETAIL ELECTRIC SALES					
Conservation only	4.3%	5.3%	5.7%	5.9%	5.9%
Low-income assistance & non-hydro renewables	5.9%	5.9%	6.3%	5.3%	5.6%
Total	10.2%	11.2%	12.0%	11.2%	11.5%

[A] Energy savings are from completed projects in that year include those from Northwest Energy Efficiency Alliance, residential behavior programs and applicable Transmission & Distribution benefit.

[B] Programmatic conservation expenditures are deferred and amortized over a 20-year period in accordance with City Council-passed resolutions and Statement No. 62 of the GASB, *Codification of Accounting and Financial Reporting Guidance Contained in Pre-November 30, 1989 FASB & AICPA Pronouncements*. Non-low income programmatic conservation includes expenditures for program measures, customer incentives, field staff salaries, energy code enforcement, and direct program administration. They do not include expenditures related to solar or other renewable programs. Low-income programmatic conservation includes these types of expenditures for the Department's HomeWise and Low-Income Multifamily Programs.

[C] Non-programmatic expenditures include program planning, evaluation, data processing, and general administration. These expenses are not associated with measured energy savings.

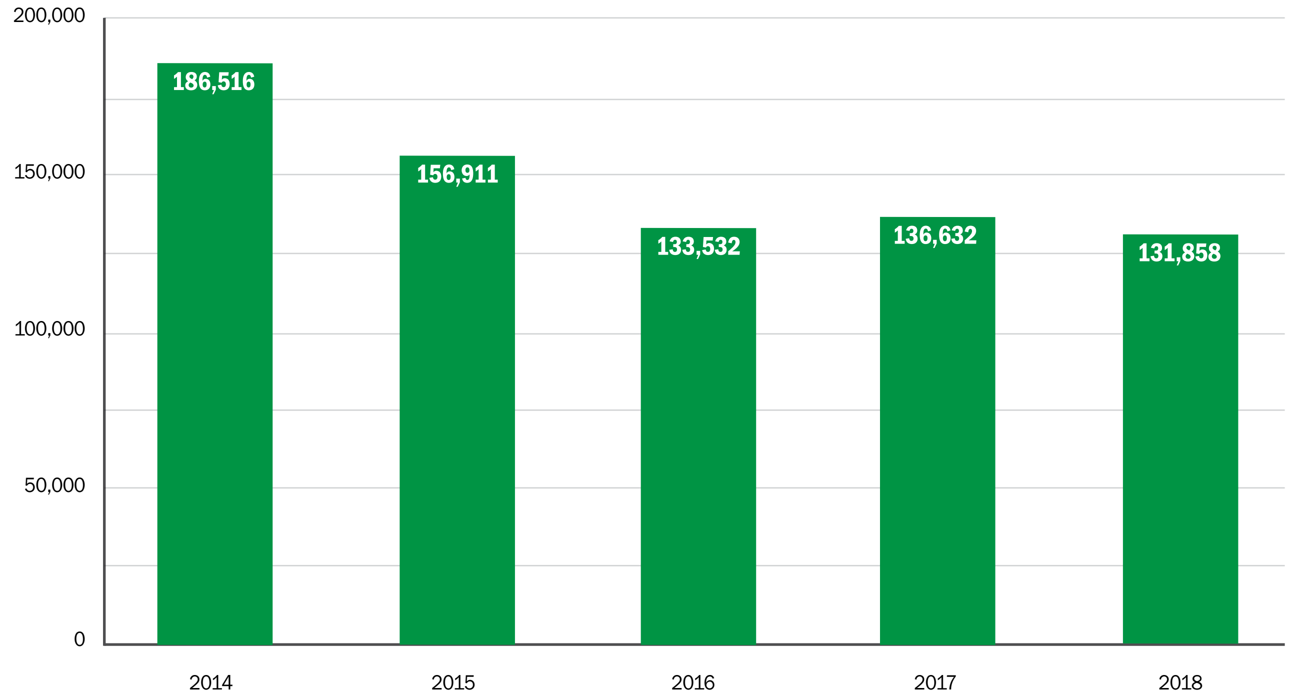
[D] Low-income assistance includes rate discounts and other programs that provide assistance to low income customers.

[E] Non-hydro renewable resources include renewable energy certificates (RECs) and RECs bundled with energy generated from various sources which are funded from current revenues to comply with State of Washington Energy Independence Act (RCW 19.285).

Note: Certain amounts from 2015 - 2014 have been revised due to updated information.

ANNUAL ENERGY SAVINGS THROUGH CONSERVATION

(megawatt hours)



Seattle City Light
700 Fifth Avenue
PO Box 34023
Seattle, WA 98124-4023
seattle.gov/light

Printed on recycled paper and FSC certified.